# IMPLEMENTING A NOVEL CYCLIC CO2 FLOOD IN PALEOZOIC REEFS

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## DISCLAIMER

## ABSTRACT

Recycled $CO_2$ is being used in this demonstration project to produce bypassed oil from the Silurian Dover 35 Niagaran pinnacle reef located in Otsego County, Michigan. $CO_2$ injection in the Dover 35 field into the Salling-Hansen 4-35A well began on May 6, 2004. A second injection well, the Salling-Hansen 1-35, commenced injection in August 2004. An increase in oil production in the Pomerzynski 5-35 producing well from 9 to 90 BOPD has occurred as a result of $CO_2$ injection and this rate appears to be stabilizing. $CO_2$ injection volume has reached approximately 1.2 BCF and miscibility pressure should be fully reached in the next several months.

The $CO_2$ injection phase of this project is now fully operational and most downhole mechanical issues have been solved and surface facility modifications have been completed. It is anticipated that filling operations will run for another 12-18 months. In most other aspects, the demonstration is going well and hydrocarbon production has been successfully increased to a stable rate of 90 BOPD. Our industry partners continue to experiment with injection rates and pressures, various downhole and surface facility mechanical configurations, and the huff-n-puff technique to develop best practices for these types of enhanced recovery projects.

Subsurface characterization is being completed using well log tomography and 3D visualizations to map facies distributions and reservoir properties in the Belle River Mills, Chester 18, Dover 35, and Dover 36 Fields. The Belle River Mills and Chester 18 fields are being used as type-fields because they have excellent log and/or core data coverage. Amplitude slicing of the log porosity, normalized gamma ray, core permeability, and core porosity curves is showing trends that indicate significant heterogeneity and compartmentalization in these reservoirs associated with the original depositional fabric and pore types of the carbonate reservoir rocks.

Digital and hard copy data continue to be compiled for the Niagaran reefs in the Michigan Basin. Technology transfer took place through technical presentations regarding visualization of the reservoir heterogeneity in these Niagaran reefs. Oral presentations were given at two Petroleum Technology Transfer Council workshops, a Michigan Oil and Gas Association Conference, a Michigan Basin Geological Society meeting, and the Eastern American Association of Petroleum Geologist’s Annual meeting. In addition, we met with our industry partners several times during 2004 to communicate and discuss the reservoir characterization and field site aspects of the demonstration project. A technical paper will be published in the April 2005 issue of the AAPG Bulletin on the characterization of the Belle River Mills Field.

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# 1.0 EXECUTIVE SUMMARY

### Goals and Results

The primary goals of this project are to:

1. Demonstrate through a field trial that significant quantities of by-passed hydrocarbons can be recovered from pinnacle reefs using a novel $CO_2$ cycling technology. The $CO_2$ will come from nearby Antrim gas processing facilities resulting in the added benefit of the $CO_2$ being sequestered rather than vented to the atmosphere.

2. Use log-curve amplitude slicing and well log tomography to develop a 3D digital model of a pinnacle reef.

3. Inventory the Michigan Basin for abandoned or shut-in reefs that are suitable candidates for similar recovery efforts. Compile pertinent engineering and geological characteristics in digital format.

4. Pass the results, economics, and data obtained from the demonstration project along to small independent producers via an aggressive technology transfer program.

<u>Field Demonstration</u>

We began injecting $CO_2$ into the Niagaran reservoir (A1 Carbonate) in the Dover 35 field in Otsego County, Michigan on May 6, 2004 using the Salling-Hansen 4-35A well (Figures 1, 2, 3 and 4). On August 1, 2004 injection began into a second well, the Salling-Hansen 1-35; the 1-35 was a producer until June, 2004. Response was measured in the Pomerzynski 5-35 in August, 2004 and by late September the 5-35 was producing approximately 90 barrels of oil per day and attempting to flow (prior production was approximately 9 BOPD; Figures 5 and 6). Our industry partners (Jordan Exploration Company, LLC and $CO_2$ supplier, Core Energy, LLC) pulled the pump and rods from the 5-35 in November 2004 and the well was flowing at rates up to approximately 300 barrels of oil per day in December 2004 (Figure 5). Wax deposition, typical in these types of wells during either primary or enhanced oil recovery operations, is occurring in the 5-35 flowline and sometimes prevents 24 run times. In January 2005 surface facilities were modified to handle greater fluid volumes and pressures from the 5-35 well. The 5-35 well was worked over to raise the tubing above the perforations to improve production performance in January 2005. The well is presently flowing approximately 90 BOPD as compared to 9 BOPD prior to $CO_2$ injection.

The field demonstration project was shifted three miles to the west to the Dover 35 Niagaran Field from the Charlton 6 Field based upon $CO_2$ availability and flooding schedules (refer to Figure 1b). The change in the demonstration well site was previously approved by the DOE. Contract negotiations between our industry partner (Jordan Exploration Company, LLC) and the $CO_2$ supplier (Core Energy, LLC) reached completion in early 2004. The State of Michigan and the Environmental Protection Agency inspected facilities and issued orders granting our industry partner's application to begin the project in March-April 2004.

Figures 3 and 4 are location maps for the Dover 35 Field area. The Salling-Hansen #4-35A (northwest well in field, blue triangle, Michigan permit number 29995) is being used to inject recycled $CO_2$ from the Dover 36 and/or Dover 33 fields and/or compressed Antrim waste $CO_2$ into the uppermost Dover 35 Niagaran (A1 Carbonate) reservoir. Injection rates are less than anticipated into the 4-35A well (approximately 1.5 MMCF per day versus the anticipated 5 MMCF per day) with cumulative injection of 300 MMCF through December 2004 (Figure 6). However, injection rates for the 1-35 well are at least 5 MMCF per day with cumulative injection of more than 750 MMCF through December 2004 (Figure 7). Figures 6 and 7 show the daily $CO_2$ injection volumes for the 4-35A and the 1-35 through early January 2005; facility downtime resulted in several time frames of zero $CO_2$ injection.

Analogs

Amplitude slice animations and 3D models and visualizations have been completed that show the distribution of the gamma ray, core porosity and core permeability amplitudes in the Belle River Mills reef. A peer reviewed technical paper describing this work will be published in the April 2005 issue of the Bulletin of the American Association of Petroleum Geologists. The AAPG is also working with us to create an internet datapage through their website that readers may access to view the actual animations referred to in the article.

Significant progress has been made modeling the Chester 18 and the Dover 35 and 36 Fields and preliminary well log tomography animations of the gamma ray and porosity have been created. Modeling results for these fields were reported in the first semi-annual technical report for 2004 (project period January 1, 2004 - June 30, 2004).

Data Compilation

Engineering data continues to be compiled for Niagaran reefs in the Michigan Basin from hard copy records of the Michigan Department of Natural Resources (DNR). A digital production database from January 1982 through July 2003 has been manipulated to create a digital report of the production for all Niagaran Fields. The DNR database has been combined with the newly compiled annual historical production data for Michigan oil and gas fields from 1932 to 1981; these digital data were compiled from printed hard copy reports. We are now able to produce annual decline plots by field from initial production to the present day for most of the oil and gas fields in Michigan.

A separate digital database has been created from the Michigan Tech well databases showing wells that were cored in the Niagaran in the Michigan Basin. A similar spreadsheet listing wells with Niagaran cores in the Michigan Basin is located on the Michigan Basin Core Research Laboratory web site at Western Michigan University [http://www.wmich.edu/geology/corelab/corelab.htm]. The Michigan Department of Natural Resources historical paper copy pressure reports for the Niagaran Reef trend have been obtained and initial reservoir pressure data from these reports is being entered into a pressure database.

### New Findings

One new key finding is that there is significant reservoir architecture variations in these carbonate reef reservoirs. We know from our 3D visualization and well log tomography work that the best permeability (connectivity) and porosity (storage capacity) does not always coincide in these reservoirs. New bottom hole pressure buildup data from wells in the Dover 35 Field is also supporting these observations from the reservoir modeling (Figure 7). Static bottom hole pressure data acquired in the 1-35 for the A1 Carbonate (blue squares, Figure 7) and the Brown Niagaran (blue diamonds, Figure 7) have diverged since injection was initiated into the A1 Carbonate. Although pressure is increasing in both zones, the separation has increased to approximately 500 psig as of December 2004 indicating the $CO_2$ being injected into the A1 Carbonate is not uniformly or fully reaching the Brown Niagaran reservoir at this time. Concurrently, the static bottom hole pressure for the Brown Niagaran in the 5-35 producer (green squares, Figure 7) has increased along a steeper slope but is delayed in time as might be expected.

Additional key findings reported in 2004 include the observation that the distribution of the log porosity in the Dover 35 and Chester 18 Reefs appears to be similar to the distribution of the core porosity and core permeability in the Belle River Mills reef. In addition, the gamma ray distribution trends in all three reefs appear similar although the Dover 35 field is relatively small (only 4 well penetrations) in comparison to the other fields. These are important observations and are significant because it means we may be able to use well log tomography visualization techniques to map the distribution of permeability and porosity in reefs without core data (most Niagaran Reef wells have at least a gamma ray and porosity log curve). By scaling the areal distribution of this relationship (calibrated with additional analogs) we may be able to predict the likely distribution of the permeability and porosity in the Dover 35 Field as well as other Niagaran reefs.

Another earlier key finding that has emerged from the continuation of our 3D visualization work during the annual reporting period is that it appears that the best permeability and porosity in the Niagaran Reefs are not necessarily coincident. In other words, *high permeability does not always indicate high porosity nor does low permeability always indicate low porosity.* It appears that the distribution of permeability and porosity in the reefs is controlled by the original depositional fabric of the carbonate rocks (i.e., vuggy, pinpoint, moldic fabrics, among others) and that subsequent diagenesis has only partially modified this original depositional and rock property fabric (i.e., dolomitization of the original limestones in the Belle River Mills, Chester 18, and Dover 33 fields has not completely removed this original fabric). The Dover 35 and 36 fields are reported in sample descriptions to be composed predominately of limestone in the Brown Niagaran, although, the A1 Carbonate porosity zone is described as being composed of 100% dolomite.

A third finding is that high-resolution images of the larger multi-well Niagaran Fields can be obtained using well log tomography. In comparison, 3D seismic is more costly and does not achieve the high vertical resolution found in the well log curves; together well log tomography and 3D seismic can yield high vertical resolution and high lateral resolution reservoir images. Tomography of the Belle River Mills and Chester 18 fields shows that these fields are really composed of five and two individual reefs or carbonate sediment production centers, respectively, that have coalesced to form what has been called a single reef field. Reservoir engineering data from previous studies by the operator in the case of the Chester 18 Field supports the interpretation of two distinct reefs or pressure/production compartments. The gamma ray, core porosity, and core permeability amplitude slicing at Belle River Mills show five likely areal subdivisions to the field.

### Lessons Learned

We have learned that in Niagaran reef reservoirs with multiple wellbores that low volume producing wells do not need to be shut in when $CO_2$ injection begins in the injection wells. That is, low volume or stripper producing wells can remain producing unless instantaneous break through of $CO_2$ occurs. This field practice benefits the Operator buy providing continued oil sales and income during the reservoir fill up period and also provides an observation well in the reservoir. This practice was followed at Dover 35 and the daily production volumes and static bottom hole buildup tests have provided insights regarding the progress of the $CO_2$ demonstration project (Figures 5, 6 and 7).

We have also learned in the Dover 35 Field that it may be a good practice to inject $CO_2$ structurally high in these reef reservoirs and produce from a structurally low position. This practice is similar to the flood configuration used in the nearby Dover 33 field (minus the horizontal and highly deviated wells) but very different than the flood configuration used in the nearby Dover 36 field (central producer and low $CO_2$ injection wells) operated by industry between 1996 and present day (see details regarding the performance of these fields in the Discussion and Results section of this report).

We have learned that the installation of a sliding sleeve in $CO_2$ injection wells is a mechanically sound practice in these types of wellbores and reservoirs. In the 1-35 well this mechanical configuration will allow our industry partner to employ a $CO_2$ huff-n-puff methodology. That is, $CO_2$ can be injected into the structurally high A1 Carbonate, injection can be halted, the sliding sleeve can then be closed off over the A1 Carbonate thereby opening the Brown Niagaran, and the well can be allowed to flow or placed on pump to produce oil. Alternately, the Brown Niagaran could be injected with $CO_2$. The Operator may then repeat the process multiple times or huff-n-puff the reservoir. Our industry partner plans to experiment with the huff-n-puff process and develop a best practice for $CO_2$ floods in these reef reservoirs as the overall reservoir pressure in Dover 35 increases during 2005.

Another observation is that highly deviated well bores may be the best solution for contacting the maximum amount of reservoir given the high lateral and vertical heterogeneities in these Niagaran reef reservoirs. In fact, <u>highly deviated wells may be more preferable than horizontal wells</u> in these types of reservoirs.

Additional lessons learned and reported on earlier are that there is no substitute for capturing the various types of Niagaran reef reservoir data and performing rigorous analysis and reservoir visualization. 3D visualization and well log tomography of the core permeability, core porosity, and gamma ray log data have revealed new observations about the distribution of important reservoir properties in the reefs that impact producibility and economics for enhanced oil recovery and gas storage practices in these reservoirs.

We have also learned early in the demonstration project that flexibility and communication must be maintained by all parties to optimize the timelines for flooding the best and most accessible reefs first (e.g., changing of demonstration project to Dover 35 from Charlton 6) to insure optimum economics and recovery. We also learned that negotiations for a $CO_2$ supply contract using waste gas from Antrim processing facilities can become very involved from a legal and contract perspective and take longer than expected.

### Applications

The sliding sleeve downhole mechanical configuration for injection wells will likely be used by our industry partners in nearby Niagaran reef fields where enhanced recovery projects using recycled $CO_2$ are planned for the near future.

Early successful results from the Dover 35 field demonstration suggest that reefs with porosity zones in the A1 Carbonate may be the best targets for $CO_2$ enhanced oil recovery (i.e., structurally and stratigraphically high zones for injection). That is, a new selection criteria for screening existing reef reservoirs to select the best candidates for detailed studies for $CO_2$ projects has likely been established. In addition, the Dover 35 demonstration project results to date and the Dover 33 and 36 producer/injection well configurations have established an additional new best practice to inject high and produce low using two or more producing wells. Also, highly deviated wells may be better for contacting maximum reservoir volume than vertical or horizontal wells in these highly heterogeneous reservoirs.

Well log tomography is showing that the reservoir properties of the Niagaran reefs in the Michigan Basin vary both horizontally and vertically. These variations in permeability, porosity, and connectivity of the reservoir rock must be considered to insure that enhanced recovery operations including $CO_2$ injection, horizontal well placement, and gas storage facilities are designed appropriately. It appears likely that previous interpretations of reservoir and production engineering data, suggesting that many Niagaran reefs deplete uniformly, are incorrect.

Reefs in the Devonian Traverse Group in the Michigan Basin and in many stratigraphic intervals in other U.S. basins are logical targets for application of 3D visualization, well log tomography, highly deviated wellbores and sliding sleeves to assist in the determination of the viability of secondary or tertiary recovery projects and $CO_2$ sequestration. Our demonstration project results and reservoir studies in combination with the technical literature on world-wide reefs suggest that most reef reservoirs may have undrained reservoir compartments.

### Future Work

Future work includes additional pressure buildup measurements in the 1-35 and 4-35A injectors and in the 5-35 producer as deemed prudent by our industry partners. Surface facility configurations will be adjusted to improve production. In addition, a test will be made of the producing potential of the Brown Niagaran (huff-n-puff production technique) using the sliding sleeve mechanical configuration in the 1-35 well. As the project progresses the operator may decide to drill a new producing well in the reef (likely highly deviated or horizontally) to access the base of the oil column in the reef and undrained reservoir compartments.

The 3D visualization and well log tomography techniques applied to our type-reef fields will be applied to the Dover 35 reef and vicinity during the future project periods. Well, field, and reservoir data will continue to be gathered for other Niagaran reefs in the Michigan Basin to identify likely candidates and screening criteria for future $CO_2$ injection and sequestration projects in these Niagaran reefs.

We plan to investigate the usefulness of the 3D seismic data provided for the Dover 35 field and vicinity by one of our industry partners, Core Energy, LLC during the next project period. This will be accomplished by reading the data tapes provided and loading the data into our LandMark SeisVision PC software for interpretation.

### Technology Transfer

We have been in contact with our industry partners on a regular basis during this reporting period to discuss and communicate reservoir architecture modeling results and observations and to discuss the ongoing injection progress, production results, pressure buildup tests, well bore mechanical configurations, surface facility modifications and regulatory issues.

A technical paper will be published in the Bulletin of the American Association of Petroleum Geologists in April 2005 entitled, "Well Log Tomography and 3D-Imaging of Core and Log Curve Amplitudes in a Niagaran Reef, Belle River Mills Field, St. Clair County, Michigan, U.S." We also plan to establish a 'datapage' on the AAPG website that readers of this technical article may access to view the full well log tomography and 3D animations for the Belle River Mills and/ or Chester 18 fields.

An article was published in the February 9, 2004 issue of the Oil and Gas Journal that highlighted our regional sample attribute mapping and fault delineation work. The annual planning meeting with our industry partners was held in Tampa, FL in early March 2004. Regional maps were posted for viewing by operators from the basin at the PTTC core workshop on March 19, 2004 in Mt. Pleasant, MI. Regional maps were also posted in a booth at the Michigan Oil and Gas Association's Annual Oil Conference on April 22, 2004 in Gaylord, MI and an oral presentation was made highlighting opportunities for exploration in the Michigan Basin. We participated at the Michigan Basin Geological Society Annual Field Excursion from April 30 to May 2 with a presentation on our basin-scale well log tomography and by attending several of the field stops in the Traverse and Dundee carbonates. Presentations were also made at the monthly northern Society of Petroleum Engineers meeting in May, 2004, the monthly Michigan Basin Geological Society meeting in May, 2004, the Michigan Basin USGS Assessment PTTC workshop in September 2004, and the Eastern AAPG Meeting in Columbus, Ohio in October 2004. A field trip was also conducted in September 2004 for the Depositional Environments class (10 students) that visited various Michigan Basin outcrops, attended the Michigan Basin Assessment PTTC workshop, and participated in core description and interpretation exercises at the Michigan Basin Core Analysis Laboratory at Western Michigan University.

Results and presentations from a portion of this technology transfer are available on the internet at *http://www.geo.mtu.edu/~aswylie/indxhtml.htm* and on our main subsurface visualization web page *http://www.geo.mtu.edu/svl/*.

# 2.0 EXPERIMENTAL

## 2.1 Well Details - Dover 35 Field

The Dover 35 field is comprised of three active wells and one abandoned producer (Figure 4). Two of the active wells, the 4-35A and the 1-35 were converted to $CO_2$ injection wells in 2004. The 5-35 remains the active producer in the field demonstration project.

Log curve abbreviations used in subsequent figures include - GR (gamma ray, api units), CALI (caliper, inches), RHOB (bulk density, gr/cm$^3$), DT or BCDT (bore hole compensated sonic log, transit time, ft/sec), PEF (photoelectric factor, barnes/electron), DIFF_GR (gamma ray difference curve, api units), LLD (laterolog deep, ohm-m), LLS (laterolog shallow, ohm-m), MML (micro-laterolog, ohm-m), MSFL (microspherically focused log, ohm-m).

### 2.1.1 Salling Hansen 4-35A

#### Overview & Well Background

Shell Oil drilled the Salling Hansen 4-35 vertical well (permit number 29947) in October 1974 but did not encounter the Brown Niagaran at total measured depth of 5564 ft. A whipstock was set at 3475 ft and the well was sidetracked to the southeast. The deviated wellbore, the Salling Hansen 4-35A (permit number 29995) encountered the Brown Niagaran 5428 ft measured depth and 5334 ft true vertical depth.

#### Location

The well bottom is located 505 ft south and 241 ft east of the surface location based upon the record of the directional survey; bottom hole closure is 559 ft and the drift angle for the deviated well bore ranged up to 21 degrees. The surface location for the 4-35A is 1284 ft from the north and 698 ft from the west line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (SE/4 NW/4 NW4, section 35, T31N, R2W). The bottom hole location is 851 ft from the south and 939 ft from the west line of section 35 (NE/4 SW/4 NW/4, section 35, T31N, R2W). Ground elevation for the well is 1099 ft above sea level and kelly bushing is 1114 ft.

#### Drilling and Casing history

The 4-35A encountered the A2 Carbonate at 4238 ft measured depth, the A2 Evaporite at 5336 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5362 ft and the Brown Niagaran (also known as the Guelph Formation) at 5426 ft (Figure 8). The well reportedly reached total depth of 5715 ft on November 21, 1974.

The well was originally cased with 16 inch casing set to 93 ft, 11 3/4 inch casing set to 812 ft, 8 5/8 casing set to 3474 ft and a 5 1/2 inch liner from 3263 ft to 5715 ft (Figure 9).

### Open hole testing, coring, mudlogging, and logging

No drill stem testing was conducted in this well and a mudlog could not be located although sample descriptions are provided for the A2 carbonate through total depth (Brown Niagaran) in the State records for the well. A borehole compensated sonic log was run in the original vertical hole on October 18, 1974. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were recorded in the deviated well bore (Figure 8).

According to the sample description report and the well logs, the A1 Carbonate contains approximately a 24 ft thick dolomite zone with neutron porosity as high as 10%; this dolomite zone was described in the cuttings description as tan to dark brown, fine crystalline, sucrosic porosity, gold to white fluorescence and yellow cut.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology. The main hydrocarbon show was recorded from 5484 to 5560 ft. The limestone was described as dark brown to tan, hard, dense, vuggy to intercrystalline porosity, abundant rhombohedral crystals, some anhydrite, trace of brown and black oil stain, some blue-white fluorescence and fine streaming cut. Neutron porosity through this interval is about 2% on average. Traces of dead oil stain were recorded between 5560 and 5715 ft total depth.

### Original Completion

The 4-35A was perforated from 5491 to 5570 ft measured depth with six holes and then acidized with 1800 gallons of 28% HCL (Figure 8 and 9). The well initial potentialed flowing 312 BOPD and 240 MCFGPD on December 21, 1974 with 200 psig tubing pressure. The well produced approximately 142 MBO and 222 MMCF gas through December 2003.

### Workover for $CO_2$ Injection

In order to prepare the 4-35A for $CO_2$ injection it was necessary to run a tie-back liner to surface from the top of the existing 51/2 inch casing during April 2004. $CO_2$ injection commenced on May 6, 2004 and through December 31, 2004 approximately 300 MM cubic feet had been injected (Figure 10).

## 2.1.2 Salling Hansen 1-35

### Overview & Well Background

Shell Oil drilled the Salling Hansen 1-35 vertical well (permit number 29236) in May 1973 and encountered the Brown Niagaran at total measured depth of 5359 ft. The Gray Niagaran was encountered at 5730 ft. The Salling Hansen 1-35 was the discovery well of the Dover 35-31N-2W Field.

### Location

The surface location for the 1-35 is 990 ft from the south and 797 ft from the east line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NW/4 SE/4 NW4, section 35, T31N, R2W). Ground elevation for the well is 1109 ft above sea level and kelly bushing is 1124 ft.

### Drilling and Casing history

The 1-35 encountered the A2 Carbonate at 5173 ft measured depth, the A2 Evaporite at 5274 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5298 ft and the Brown Niagaran (also known as the Guelph Formation) at 5359 ft (Figure 11). The well reportedly reached total depth of 5780 ft on May 25, 1973.

The well was originally cased with 16 inch casing set to 117 ft, 11 3/4 inch casing set to 872 ft, 8 5/8 casing set to 3514 ft and a 5 1/2 inch liner from 3257 ft to 5770 ft (Figure 12).

### Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located although sample descriptions are provided for the A2 carbonate through total depth (Gray Niagaran) in the State records for the well. A borehole compensated sonic log was run in the well on May 24, 1973. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were also recorded in the well bore (Figure 11).

According to the sample description report and the well logs, the A1 Carbonate contains approximately 30 ft of dolomite with neutron porosity as high as 14% (5318-5340 ft); this dolomite zone was described in the cuttings description as dark brown, fine crystalline, with intercrystalline porosity and some vugs, bright yellow fluorescence and no cut.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology with one dolomite zone from 5640-5670 ft. The main hydrocarbon shows were recorded from 5346 to 5540 ft. The limestone was described as tan, brown and dark grey, fine to medium crystalline, crystals on edge of cuttings (could be rhombohedral calcite or dolomite?), bright yellow fluorescence, trace cut with fair cut when crushed.

### Original Completion

The 1-35 was perforated at 5475, 5480, 5492, 5500, 5510, 5516 ft measured depth with six holes and then acidized with 3500 gallons of 28% HCL (Figure 11 and 12). The well initial potentialed flowing 384 BOPD and 172 MCFGPD on June 3, 1973 with 549 psig tubing pressure. Oil gravity was 42.3 and gas-oil ratio 449/1. Initial choke size was 15/64th. The well produced approximately 710 MBO and 549MMCF gas through December 2003.

### Workover for $CO_2$ Injection

The 1-35 was taken off production in the second quarter of 2004 and converted to a $CO_2$ injection well. A tie-back liner was run in the well. A sliding sleeve downhole assembly was installed in the wellbore so either set of perfs, A1 Carbonate or Brown Niagaran, could be used for injection (refer to Figures 11 and 12). The sliding sleeve assembly will also allow the well to be operated as a huff-n-puff well (injection into upper perfs and production from lower perfs). The well has performed very well under injection and had cumulative injection of 750 MMCF of $CO_2$ through December 31, 2004 (Figure 13).

## 2.1.3 Pomerzynski 5-35

### Overview & Well Background

Shell Oil drilled the Pomerzynski 5-35 vertical well (permit number 37324) in December 1983 and encountered the Brown Niagaran at total measured depth of approximately 5603 ft. It is postulated that the Pomerzynski 5-35 was drilled to locate bypassed oil in the Dover 35 Field.

### Location

The surface location for the 5-35 is 330 ft from the north and 1021 ft from the east line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NW/4, NE/4, SW4, section 35, T31N, R2W). Ground elevation for the well is 1129 ft above sea level and kelly bushing is 1140 ft.

### Drilling and Casing history

The 5-35 encountered the A2 Carbonate at 5254 ft measured depth, the A2 Evaporite at 5351 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5574 ft and the Brown Niagaran (also known as the Guelph Formation) at 5603 ft (Figure 14). The well reportedly reached total depth of 5715 ft (measured depth driller) or 5668 ft (measured depth logger) on December 20, 1983.

The well was originally cased with 16 inch casing set to 80 ft, 11 3/4 inch casing set to 753 ft, 8 5/8 casing set to 3082 ft (possibly 3583 ft) and a 5 1/2 inch liner from approximately 3200 ft to 5715 ft (Figure 15).

### Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located. No detailed report of lithology and show information in the well could be located. A lithodensity-compensated neutron log was run in the well on December 20, 1983. A dual laterolog and a microlaterolog were also recorded in the well bore (Figure 14).

### Original Completion

The 5-35 was perforated from 5514-4419, 5524-5535, and 5575-5588 ft measured depth and then acidized with 5000 gallons of 28% HCL (Figure 14 and 15). The well initial potentialed pumping 85 BOPD and 85 MCFGPD on January 20, 1984. Oil gravity was 40.7. The well produced approximately 68 MBO and 44 MMCF gas through December 2003.

### Workovers for Production

The 5-35 was producing approximately 9 BOPD from the start of injection into the 4-35A in May 2004 until two weeks after the start of injection into the 1-35 when production increased to approximately 90 BOPD. The well was pumping 100% of the time and trying to flow. Our industry partners elected to pull the pump and rods out of the well in October 2004 and attempted to swab the well in; three bottom hole pressure buildup tests were also conducted during this time. Finally, in November 2004 the well began to flow at daily rates up to 300 BOPD (Figure 16).

However, the 5-35 was still experiencing two mechanical problems in early December 2004. One problem had to do with the surface processing facilities and flow lines and their capacities and these issues were resolved in early January 2005 by our industry partners. A new three inch flow line was laid from the well to the surface facilities and a dedicated high pressure separator was installed. The second problem was the position of the base of the production tubing in the well relative to the perforations (Figure 15). The perforations were 150 ft above the base of tubing which was resulting in the well loading up and killing itself. This configuration was appropriate for the well when it was pumping, but now that the well was flowing, the bottom of the tubing needed to be above the perforations. Our industry partner brought in a work over rig to pull the tubing in mid-January 2005 and the downhole mechanical configuration was modified to handle the flowing conditions. The well appears to be stabilizing and is flowing approximately 90 BOPD.

## 2.1.4 Pomerzynski 2-35

### Overview & Well Background

Shell Oil drilled the Pomerzynski 2-35 vertical well (permit number 29374) in September 1973 and encountered the Brown Niagaran at total measured depth of approximately 5470 ft. The Gray Niagaran was encountered at 5685 ft.

### Location

The surface location for the 2-35 is 508 ft from the north and 800 ft from the west line of the northwest quarter of section 35, township 31 north, range 2 west, Dover Township, Otsego County, Michigan (NE/4, NW/4, SW4, section 35, T31N, R2W). Ground elevation for the well is 1128 ft above sea level and kelly bushing is 1140 ft.

### Drilling and Casing history

The 2-35 encountered the A2 Carbonate at 5227 ft measured depth, the A2 Evaporite at 5320 ft measured depth, the A1 Carbonate (also known as the Ruff Formation) at 5359 ft and the Brown Niagaran (also known as the Guelph Formation) at 5470 ft (Figure 17). The well reportedly reached total depth of 5760 ft (measured depth driller) on December 25, 1973.

The well was originally cased with 16 inch casing set to 66 ft, 11 3/4 inch casing set to 755 ft, 8 5/8 casing set to 3560 ft and a 5 1/2 inch liner from approximately 3200 ft to 5760 ft.

### Open hole testing, coring, mudlogging, and logging

Drill stem testing was not conducted in this well and a mudlog could not be located although sample descriptions are available for the A2 carbonate through total depth (Gray Niagaran) in the State records for the well. A borehole compensated sonic log was run in the well on September 25, 1973. Dual laterolog, microlaterolog, and sidewall neutron porosity logs were also recorded in the well bore (Figure 17).

According to the sample description report and the well logs, the A1 Carbonate contains approximately 65 ft of dolomite with neutron porosity of 2% (5360-5425 ft); this dolomite zone was described in the cuttings description as buff, finely sucrosic and vuggy porosity, fair stain, no fluorescence, finely crystalline and argillaceous.

Sample descriptions through the Brown Niagaran show limestone to be the principle lithology. The main hydrocarbon shows were recorded from 5440 to 5530 ft. The limestone through this interval was described as buff to white, trace dolomite, slightly sucrosic to finely crystalline, argillaceous, fair porosity, good bright yellow fluorescence, no cut and dead oil stain. Only trace to poor fluorescence was described in the lower Brown Niagaran.

### Original Completion

The 2-35 was perforated from 5450-5540 ft measured depth with 16 holes and then acidized with 1350 gallons of 15% HCL; the well was acidized again with 3000 gallons of 28% HCL. The well initial potentialed flowing 300 BOPD and 204 MCFGPD on October 22, 1973. Tubing pressure was 290 psig. The well produced approximately 32 MBO and 20 MMCF gas through October 1987.

### Abandonment

The 2-35 well was permanently abandoned on October 14, 1987 probably due to poor performance.

## 2.2 Log Data

### 2.2.1 Log Data Capture

Paper copies of the well logs for the Dover 35, Charlton 6, Belle River Mills and Chester 18 Fields and surrounding area were obtained from the files at Michigan Tech and scanned to create tagged image format (tif) digital images using the commercial Neuralog software and a 36-inch scanner. Neuralog software was used to digitize the gamma ray and/or transit time (sonic), bulk density, neutron, and resistivity log curves for each well; the resistivity curves were not captured for Belle River Mills due to their vintage and low vertical resolution. Log ASCII Standard 2.0 (LAS) files were output from the Neuralog software to use in subsurface interpretations, log curve amplitude slicing and cross sections.

## 2.3 Production Data Capture

Digital monthly production data records from January 1982 through June 2003 were obtained from the Michigan Department of Natural Resources in a series of MS Access data files and then recombined into one composite MS Access database. This database contains field names and monthly oil, gas, natural gas liquids, and water production volumes among other data elements. These data can be used to create monthly decline plots for wells, production units, and fields. If the field went on line post January 1982 these data can be summed to determine cumulative production for the field for the period January 1982 through June 2003.

Historical monthly production records prior to January 1982 are not available in digital format from the State of Michigan at this time. Therefore, hardcopy annual reports from 1932 through 1984 were obtained with annual production data and entered into our digital production database. This will enable us to create historical decline plots for Niagaran fields to use to analyze the performance of individual wells and groups of reservoirs (see Discussion and Results section).

## 2.4 Data Processing for 3D Visualization

Rockware's Rockworks2002™ suite of software (version 3.5.23) that is capable of excellent 3D manipulation, visualization, and animations was used for 3D-imaging. The key step with the software is the data preparation or data processing to place the various types of data (i.e., logs, tops, locations, etc.) into the required formats for loading into the program. An in house routine has been developed whereby the well and log data is first manipulated in an SQL database and then used to populate the 3D program's spreadsheet loader; however, when file length exceeds spreadsheet limits a series of ASCII text files must be used to load the data into the program. Drawbacks to the program are that all data must be reloaded each time new data is added to a project and the 3D visualization module of the program performs slowly when 0.3 m (1 ft) sample increment log data is loaded for an entire project; a subset must be used to decrease processing and redraw times.

## 2.5 Well Log Tomography

Well log tomography also known as log curve amplitude slicing (Wylie and Wood, 2005; Wylie and Huntoon, 2003; Wylie, 2002) is a form of tomography that utilizes the full vertical resolution of geophysical well log curves. Amplitude slices represent *approximate* time lines when the interval under analysis is bounded by unconformities or other chronostratigraphic surfaces and show the inferred distribution of lithofacies at the time of deposition. Computer animation allows visualization of changes in the distribution of lithofacies between successive slices or timelines. The distribution of other reservoir properties including porosity, permeability, and water saturation can also be visualized using the technique. The software used to create the tomographic animations includes MS Access, Golden Software Surfer, JASC Paintshop Pro Animator, and an in-house Visual Basic program.

In the case of the Niagaran reefs, only one chronostratigraphic surface is used. The base of the reef (or estimated base of the reef) in each well penetrating a reef is being used to establish one approximate time surface. Bottom-up slicing is then applied utilizing both reef and/or non-reef well penetrations to visualize the distribution of any particular log curve amplitude or other regularly sampled (in depth) reservoir property such as core permeability or core porosity measurements.

## 2.6 3D Seismic Data

One of our industry partners, Core Energy, LLC., has provided us with a 3D seismic data volume over the Dover 35 Field and vicinity that was acquired by a previous owner of the Dover 35 field in about 1996 (Figure 18). The data arrived on 8 millimeter tapes that need to be read using a tape drive and copied to our network disk space. Accompanying trajectory and spatial information will be used to load the data into our LandMark SeisVision PC software for interpretation and analysis during the next project period.

## 2.7 Difference Log

We have developed a new technique to visualize the stratal units and surfaces in carbonate rocks. This technique uses the difference between successive log amplitude samples to create a difference curve as a proxy for the rate of change seen in well log curve amplitudes. Examples of the gamma ray difference curve are shown on the well logs in Track 2 (DIFF_GR curve) in Figures 8, 11, 14, and 17 and in the cross section in Figure 19. By plotting the difference in amplitude between successive gamma ray amplitudes (1 ft sample increment) using a 'block' curve presentation and then expanding the scale to maximize the visualization of the difference, new observations are being made about cyclicity, vertical heterogeneity, and subtle stratal units in these reef carbonate rocks. The difference log presentation for the gamma ray and other well log curves may have important implications for correlating stratigraphic sequences, inferring chronostratigraphic surfaces and modeling reservoir properties in all types of carbonate and siliciclastic rocks. We plan to continue our evaluation of this new interpretation technique and will report additional results in future reporting periods.

# 3.0 RESULTS AND DISCUSSION

## 3.1 Dover 35, 33 and 36 - Field Characteristics and Performance Comparisons

The location of the Dover 35, 33 and 36 Fields in relation to each other is shown in Figures 1b and 3. Figure 20 shows the reservoir characteristics for each field for comparison purposes. One point of interest is the Lithology for the three fields through the A1 Carbonate and Brown Niagaran zones. The A1 Carbonate porosity zone, where present, is normally 100% Dolomite. However, careful review of the Michigan Department of Natural Resources sample description information through the Brown Niagaran in each of the wells in the fields shows this interval in the Dover 35 and 36 fields to be composed of almost 100% Limestone while in the Dover 33 field the Brown Niagaran interval is composed of 100% Dolomite. However, comparison of other reservoir characteristics shown in Figure 20 reveal no other remarkable differences between the fields.

Historical and predicted primary and enhanced oil recovery performance for Dover 35, 33 and 36 is shown in Figure 21. Although, the reservoir characteristics of the three fields are similar the Dover 33 and 36 fields performed very differently under $CO_2$ flood. Approximately 20.5 BCF of $CO_2$ has been injected into the Dover 33 field through December 31, 2004 resulting in 450,000 barrels of tertiary oil recovery (Figure 22). In contrast, approximately 5.4 BCF of $CO_2$ has been injected into Dover 36 field through December 31, 2004 resulting in 220,000 barrels of tertiary oil recovery (Figure 23). $CO_2$ injection pressures were approximately double for the Dover 36 field versus the Dover 33 field. Based upon our studies of these fields and our industry partner's operational experience with these fields, we believe the tertiary recovery performance differences are likely due to reservoir heterogeneity and how this heterogeneity was contacted relative to the placement of injection and production wells in these reservoirs (e.g., vertical, horizontal or highly deviated wells and locations of injection and production wells relative to the crest or base of reefs). Salt plugging of porosity in these reefs could also play a role in the performance differences measured between the Dover 33 and 36 fields.

## 3.2 Dover 35 Field

$CO_2$ injection into the 4-35A and 1-35 wells in the uppermost portion of the Niagaran reservoir (A1 Carbonate) in the Dover 35 Demonstration project has resulted in an oil production response in the producing well, the Pomerzynski 5-35. Production has increased from 9 BOPD to a fairly stabilized rate of 90 BOPD (refer to Figures 5, 6 and 7). This is a very favorable early result for the demonstration project considering the downhole and facility mechanical issues that our industry partners have experienced and continue to mitigate in order to improve production and injection performance.

Injection rates for the 4-35A have been lower than expected (approximately 2 MMCF per day actual versus 5 MMCF per day expected). We believe the lower injectivity in the 4-35A is likely due to a disconnect of the A1 Carbonate zone in this well with the A1 Carbonate zone in the 1-35 and 5-35 wells (refer to cross section, Figure 19). In other words, these apparently similar appearing zones on the well log correlations are actually two separate porosity zones that may not be in connection with each other and in the case of the 4-35A, may not be in connection with the underlying Brown Niagaran. This disconnect interpretation can be supported, in part, by the divergence and different slopes of the static bottom hole pressure measurements shown in Figure 7. It is also likely that the production response in the 5-35 that occurred soon after injection began into the 1-35 indicates early $CO_2$ breakthrough via the A1 Carbonate. Furthermore, the bottom hole pressure measurements from the Brown Niagaran seem to indicate that the $CO_2$ being injected into the A1 Carbonate is finding its way into the Brown Niagaran, albeit at a slower rate and likely more tortuous route, then in the A1 Carbonate. What is not clear at this time, is the relative contribution by the 4-35A and the 1-35 to the overall reservoir pressure increase in the Brown Niagaran in the 5-35 producing well measured by the bottom hole pressure trends (Figure 7). What is known is that the 1-35 is taking at least twice the volume of $CO_2$ that the 4-35A is taking. Our industry partner is analyzing this situation and plans to take additional bottom hole pressure measurements and adjust mechanical configurations during the next project period in an attempt to further understand the causes of this injectivity difference. It will be interesting to observe if the static bottom hole pressure differences between the A1 Carbonate and Brown Niagaran decrease or converge as injection (A1 Carbonate only) continues into the reservoir.

Consideration has been given to adding additional perforations at lower positions in the reservoir to improve injectivity. However, at this time, our industry partners continue to prefer not to perforate either the 4-35A or the 1-35 injection wells deeper in the reservoir because of potential productivity losses related to gravity drainage. Dover 35 recovered approximately 966,000 barrels of oil from primary production, and we estimate between 235,000 and 585,000 barrels of additional oil will be recovered as a result of the $CO_2$ flood demonstration project.

Reservoir characterization of the Dover 35 Field is continuing. Well logs in the field and vicinity have been digitized (Dover 36 and Charlton 6 completed, Dover 33 in progress) and historical production data has been gathered from the Michigan Department of Environmental Quality hard copy records. Figure 19 shows a structural cross section through the 4 wells in the field with the A2 Carbonate, A1 Carbonate, Brown Niagaran, and Gray Niagaran correlations. The 4-35A and the 1-35 wells are being used as $CO_2$ injectors and the 5-35 well is the producer in the demonstration project. The cross section shows the original perforated intervals and in combination with the wellbore diagrams (refer to Figures 9, 12 and 15) depicts the current downhole mechanical configurations. Variability in the Neutron Porosity, Borehole Compensated Sonic, and Resistivity amplitudes between the four wells (Porosity and Resistivity tracks, Figure 19) indicate significant vertical and lateral heterogeneity exists in the reef carbonates. Well log tomography animations of the neutron porosity and gamma ray amplitudes in the four wells in Dover 35 and the three wells in Dover 36 appear to validate the high lateral and vertical heterogeneity in this single reef reservoir. Figure 24 shows five example bottom up and top down slices of neutron porosity and gamma ray amplitudes through these two reefs. We intend to incorporate the borehole compensated sonic log curves and the resistivity log curves from the four wells in the Dover 35 field as well as the 3D seismic into our reservoir model during a future reporting period.

## 3.3 Dover 33 Review and Historical Performance

The Dover 33 Field was discovered in 1974 and covers an area of about 100 acres (refer to Figures 1b and 3). Four wells were drilled early in the primary phase of production. In 1996 one of the original producers (Lawnichak Myskier 1-33, permit number 29565) was converted to a $CO_2$ injection well. The 1-33 well is located in a crestal structural position in the reef. Production was shut in until minimum miscibility pressure was reached in early 1997 about nine months after injection began (Figure 22). Approximately 2.7 BCF of $CO_2$ was injected to reach minimum miscibility pressure (~1200 psia). Total $CO_2$ injected/cycled is about 21 BCF through December 2004.

A new vertical well (2-33, permit number 50985) was drilled in the Dover 33 field in November 1996 to a total measured depth of 5774 ft but encountered only 100 ft of dolomite with no shows in the toe of the reef and was abandoned; the other original vertical producing wells were plugged and abandoned prior to conversion for $CO_2$ flooding. The 2-33 was plugged back and a whipstock was used to drill the well horizontally to the northwest (permit number 51601). 5 1/2 inch casing was set through the turn to 4860 ft measured depth and the well was drilled horizontally 1714 ft to a total measured depth of 6990 ft. The well was completed open hole through the horizontal section. Performance information for this well is unavailable at this time. In late 2003 this well was plugged back and a whipstock was set to redrill the well (2-33HD2) to place the horizontal portion lower in the reservoir just above the interpreted oil-water contact. Unfortunately, the well ran low into the water leg of the reservoir. The horizontal well was plugged back and redrilled again (2-33HD4, permit number 55942) in December 2003 to a slightly higher position in the reservoir. Full performance information for the producing 2-33HD4 is unavailable at this time.

The 5-33HD1 was drilled immediately following the 2-33HD1 in late 1996. The 5-33HD1 (permit number 51603) was drilled at a high angle 1281 ft to the southwest. 5 1/2 inch casing was set to total measured depth of 6456 ft. The well was completed in January 1997 through perforations and tested flowing 224 BOPD of 47.9 gravity and 700 MCF of $CO_2$.

Due to operational and performance issues related to Dover 33, 35 and 36 our industry partner, Core Energy, LLC, the operator of Dover 33, reduced $CO_2$ injection into the Dover 33 field in 2004.

## 3.4 Dover 36 Review and Historical Performance

The Dover 36 Field was discovered in 1973 and covers an area of about 200 acres (refer to Figures 1b and 3). Three wells were drilled early in the primary phase of production. In early 1997 two of the original producers (State Dover Kubacki 1-36 and Kubacki State 3-35, permit numbers 29235 and 29348) were converted to $CO_2$ injection wells. The Kubacki Cole 2-36 well located in the central area of the reef was planned as the producer for the $CO_2$ flood. A new vertical well, the Kubacki Cole 3-36 (permit number 52719 and twin to 2-36) was drilled into the reservoir in July 1998 to replace the 2-36 well; the 2-36 was plugged and abandoned. In 1997 the 3-35 was reentered and a horizontal leg was added extending approximately 1000 ft to the northeast. Both the vertical and openhole horizontal legs of the wellbore have been used for $CO_2$ injection

Production was shut in until minimum miscibility pressure was reached in late 1998 about 29 months after injection began (Figure 23). Approximately 2.1 BCF of $CO_2$ was injected to reach minimum miscibility pressure (~1200 psia). Total $CO_2$ injected/cycled is about 5.4 BCF through December 2004.

## 3.5 Summary

The Dover 33 field has performed well under $CO_2$ injection recovering 450,000 barrels of incremental oil, about 37% of the primary production and approximately 10% of the original oil in place (Figures 25 and 26). The primary plus tertiary recovery factor is about 42%. Most of this oil was recovered in the first three years of the project (refer to Figure 22). The injection/production pattern for the field, one crestal injector (practice being followed for Dover 35) likely resulted in maximizing the gravity aspects of $CO_2$ miscible flooding. The strategy of placing two horizontal/highly deviated producers through the reservoir likely maximized the reservoir contact area for production. However, it may be possible to improve the tertiary recovery in future $CO_2$ floods of Niagaran reefs through improved modeling and well placement (more horizontal wells? highly deviated wells? if economically viable) and through injection and/or production and/or facility best practices.

The Dover 36 field has recovered approximately half the incremental oil recovered in the Dover 33 field (Figures 25 and 26). Under $CO_2$ injection, the Dover 36 field has recovered 220,000 barrels of incremental oil, about 19% of the primary production and approximately 5% of the estimated original oil in place. The primary plus tertiary recovery factor is about 36%. The oil continues to be recovered at good rates (~80 BOPD) and these rates may continue for several more years (refer to Figures 23, 25 and 26). These longer lived and lower production volumes contrast with the higher initial rates of production measured in the Dover 33 flood. The injection/production pattern for the Dover 36 field, one crestal producer and two flank injectors, is believed to have resulted in the lower incremental recovery to date using $CO_2$ miscible flooding.

We expect Dover 35 to perform more like Dover 33 (refer to Figures 25 and 26) based upon reservoir characterization and flood and mechanical configurations. We estimate that Dover 35 will recover from 235,000 to 585,000 barrels of oil from $CO_2$ injection. Dover 35 daily oil production and cumulative $CO_2$ injection from January 2004 through early January 2005 is shown in Figure 27. Dover 35 is in the beginning stage of response from the $CO_2$ injection.

## 3.6 Technology Transfer Activities

### 3.6.1 Presentations

Petroleum Technology Transfer Council, Mt. Pleasant, MI (March 19, 2004) "Imaging of Niagaran Fields Using Well Log Tomography and 3D Visualization", A. Wylie.

Michigan Oil and Gas Association, Gaylord, MI, (April 22, 2004) "Exploitation and Exploration Opportunities in Michigan - New Views of a Mature Basin or Practical Technology combined with Old Fashioned Prospecting", A. Wylie.

Society of Petroleum Engineers, Traverse City, MI (May 16-18, 2004) “Application of Well Log Tomography to the Dundee and Rogers City Limestones, Michigan Basin, USA”, J. Wood.

Michigan Basin Geological Society, Traverse City, MI (May 19, 2004) "Alternate Views of Well Logs Using Well Log Tomography", A. Wylie.

Petroleum Technology Transfer Council, Grand Rapids, MI (September 23, 2004) "Views of Existing and Prospective Producing Formations in Michigan", A. Wylie. Included four-day field trip with 10 students, participation by students in PTTC workshop, visits to various outcrops, exercises in core description at the Western Michigan University Michigan Core Repository.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) “Map views of the producing formations in Michigan, the Michigan Basin, U. S.”, A. Wylie and J. Wood.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) “Depositional patterns in the Trenton and Black River Formations revealed by well log tomography and K-bentonite time planes, Michigan Basin and beyond”, A. Wylie.

AAPG Eastern Meeting, Columbus, OH (October 3-6, 2004) “Application of well log tomography to the Dundee and Rogers City Limestones, Michigan Basin, U. S.”, J. Wood.

### 3.6.2 Meetings with Jordan Exploration Company, LLC and Core Energy, LLC

February 1-4, 2004, Traverse City, Meeting to discuss Dover 35 project.

March 7-14, 2004, Annual Project Meeting and Field Trip to view carbonate depositional environments in the Florida Keys in conjunction with Western Michigan University; included student participants and presentations.

April 21-23, 2004, Traverse City, Meeting to discuss Dover 35 project.

May 16-18, 2004, Traverse City, Meeting to discuss Dover 35 project.

June 3-8, 2004, Traverse City, Meeting to discuss Dover 35 project.

July 8, 2004, Traverse City, Meeting to discuss Dover 35 project.

September 9-12, 2004, Traverse City, Meeting to discuss Dover 35 project.

November 9-17, 2004, Traverse City, Meeting to discuss Dover 35 project.

### 3.6.3 Publications

Wylie, A. S., Jr. and Wood, J. R., in press, 3D-Imaging of Core and Log Curve Amplitudes in a Niagaran Reef, Belle River Mills Field, St. Clair County, Michigan, U.S.: AAPG Bulletin, expected publication April, 2005.

Wood, J. R., Wylie, A. S., Jr., and Quinlan, W., 2004, Surface Geochemical results complement conventional approaches: World Oil, v. 225, no. 12, p. 54-57.

Wylie, A. S., Jr. and Wood, J. R., and Harrison, W. B., III, 2004, Michigan Trenton-Black River opportunities identified with sample attribute mapping: Oil and Gas Journal, v. 102, no. 6, February 9, 2004, p. 29-35.

# 4.0 CONCLUSION

The injection of $CO_2$ into the Niagaran reservoir in the Dover 35 field in Otsego County, Michigan began on May 6, 2004 using the Salling-Hansen 4-35A well. In August 2004 the Salling-Hansen 1-35 was converted from a producer to an injector and placed on injection. Approximately 1.2 BCF of $CO_2$ has been injected into the reservoir using these two wells through December 2004. An increase in oil production in the Pomerzynski 5-35 from 9 to 90 BOPD has occurred as a result of $CO_2$ injection and miscibility pressure should be achieved during the next reporting period.

The $CO_2$ injection phase of this project is now fully operational and most downhole mechanical issues and surface facility modifications have been completed. It is anticipated that filling operations will now run for another 12-18 months. In most other aspects the demonstration is going well and hydrocarbon production has increased to a relatively stable rate of 90 BOPD. Our industry partners continue to experiment with injection rates and pressures and the huff-n-puff technique to develop best practices for these types of enhanced recovery projects.

A twelve month no-cost extension for this project was requested and approved in late 2004 to complete the injection and fully access the operations. The final report will compare the performance of this demonstration with the two previous $CO_2$ injection programs in nearby reefs. Work will continue on characterization of the Dover reefs and the identification of additional reefs for $CO_2$ enhanced recovery projects.

Well log tomography and 3D imaging of the core permeability, core porosity and/or gamma ray and porosity curves for the Belle River Mills, Chester 18, and Dover 35 reservoirs is underway or has been completed. Results indicate significant heterogeneity exists in Niagaran reefs that could impact reservoir performance. This heterogeneity should be considered in the planning of primary, secondary, tertiary or gas storage projects in these types of fields. Highly deviated well bores may be the best answer for contacting the greatest amount of the re-energized hydrocarbon column in these highly heterogeneous carbonate reefs.

# 5.0 REFERENCES

Wylie, A. S., Jr., 2002, Log Curve Amplitude Slicing - Visualization of well log amplitudes for paleogeographic reconstruction of the Middle Devonian Traverse Group, Michigan Basin: Ph. D. dissertation, Michigan Technological University, Houghton, MI, 250 p.

Wylie, A. S., Jr. and Huntoon, J. E., 2003, Log Curve Amplitude Slicing - Visualization of Log Data and Depositional Environments for the Devonian Traverse Group, Michigan Basin, U. S.: AAPG Bulletin, v. 87, no. 4, p. 581-608.

Wylie, A. S., Jr. and Wood, J. R., in press, 3D-Imaging of Core and Log Curve Amplitudes in a Niagaran Reef, Belle River Mills Field, St. Clair County, Michigan, U.S.: AAPG Bulletin, expected publication April 2005.

# 6.0 FIGURES

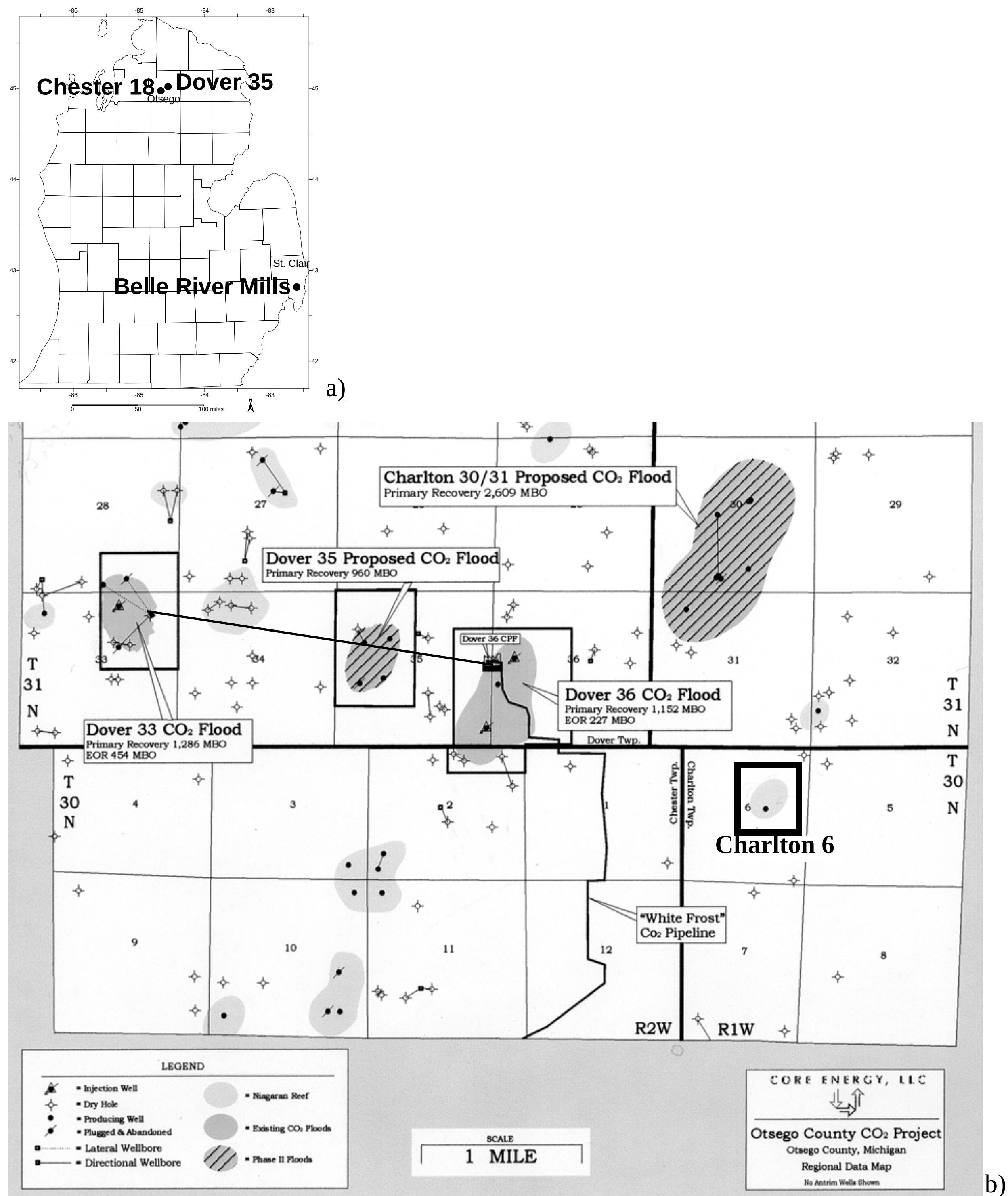



Figure 1. (a) Location of Dover 35, Chester 18 Fields in Otsego County, and Belle River Mills Field in St. Clair County, Michigan. (b) Location map for Dover 35 demonstration project area showing CO2 supply and distribution pipelines, old demonstration site, Charlton 6 and new demonstration site, Dover 35 (courtesy of Core Energy, LLC).

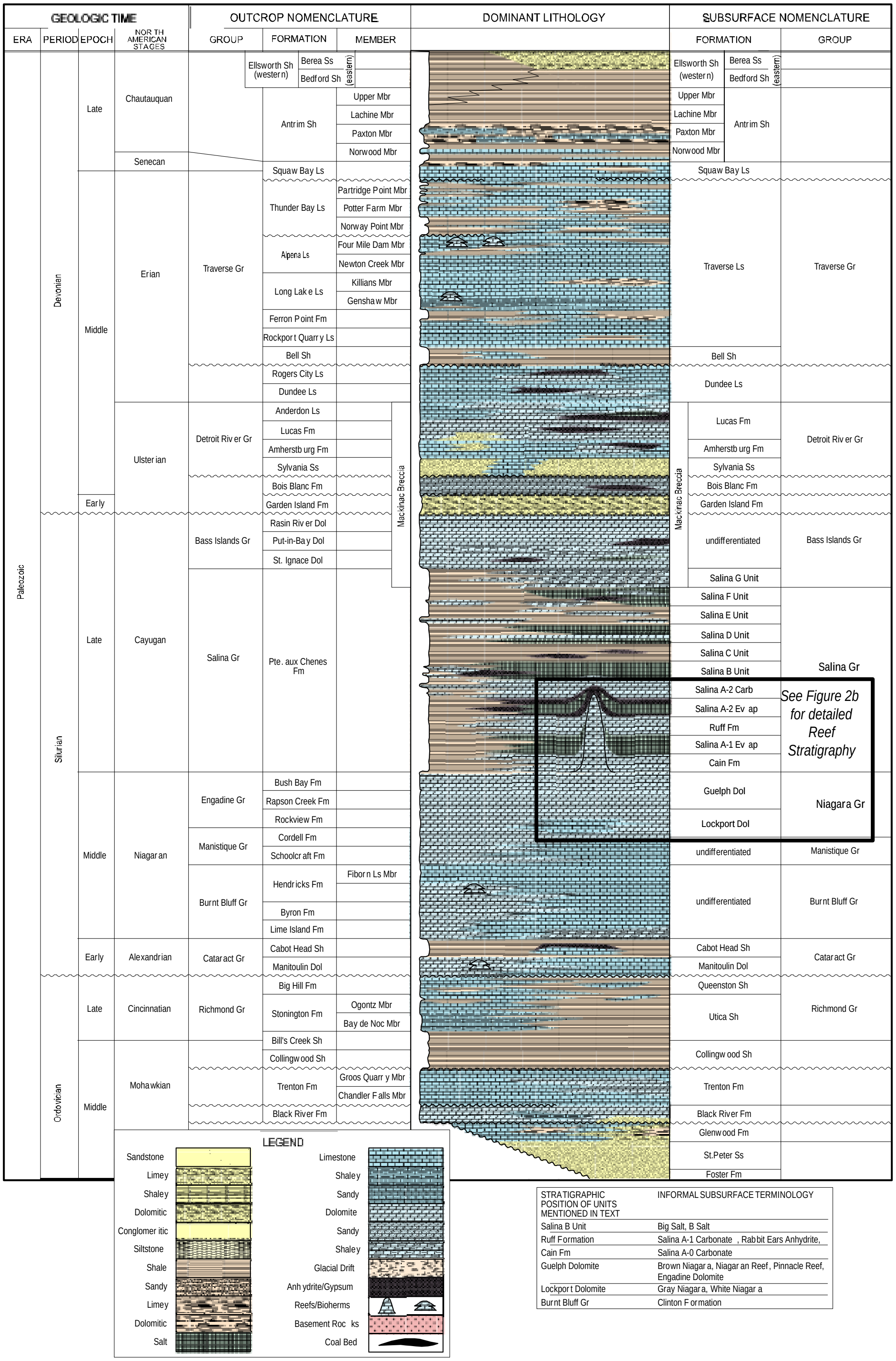



Figure 2a. Generalized stratigraphic column for the Michigan Basin.

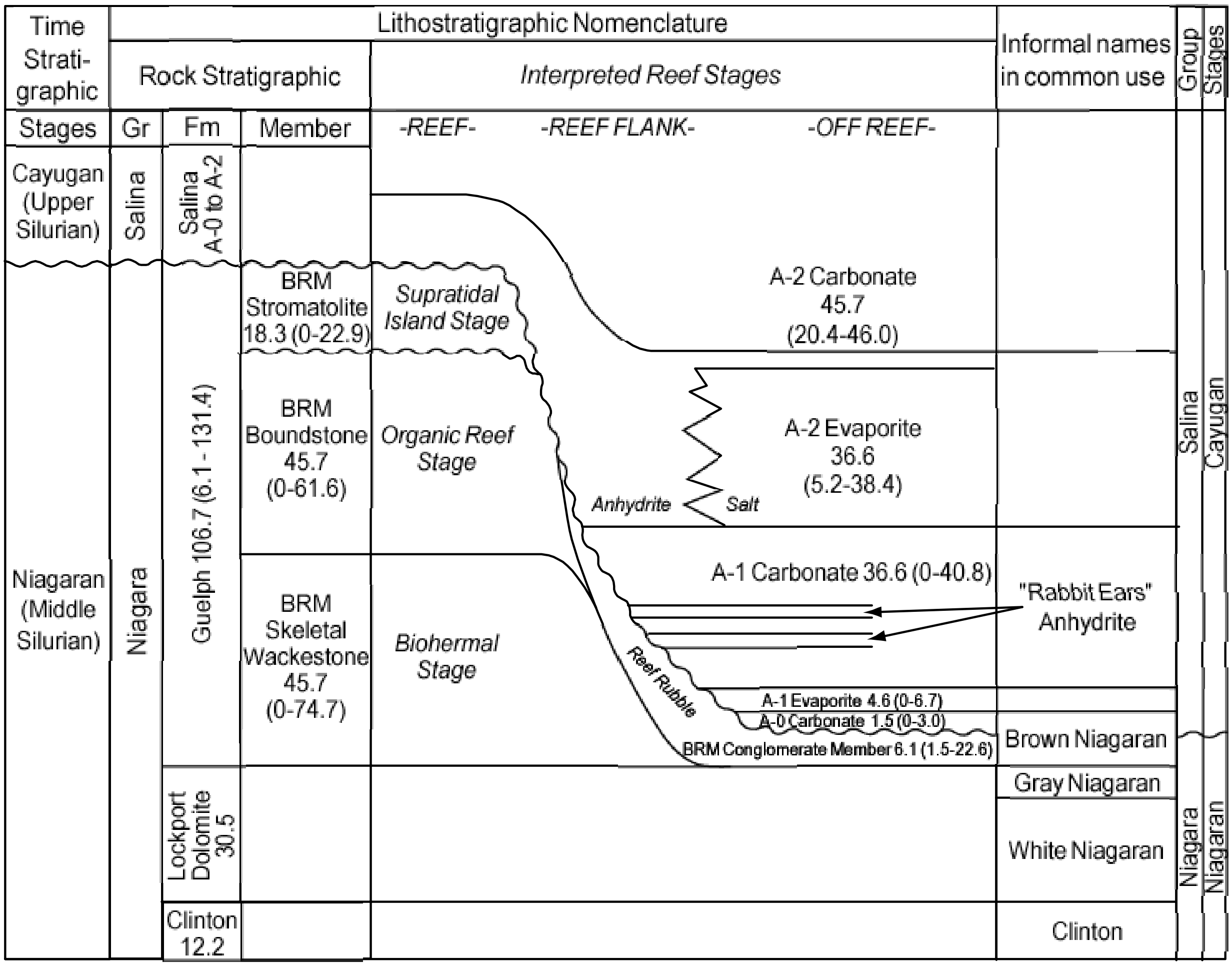



Figure 2b. Stratigraphic column showing subsurface nomenclature and correlations in the vicinity of the Belle River Mills Field (BRM), St. Clair County, Michigan as described by Gill (1977a) and reprinted with the permission of the Michigan Basin Geological Society. Average rock unit thicknesses and thickness ranges are shown in meters. Gill's subsurface nomenclature is followed in the text.

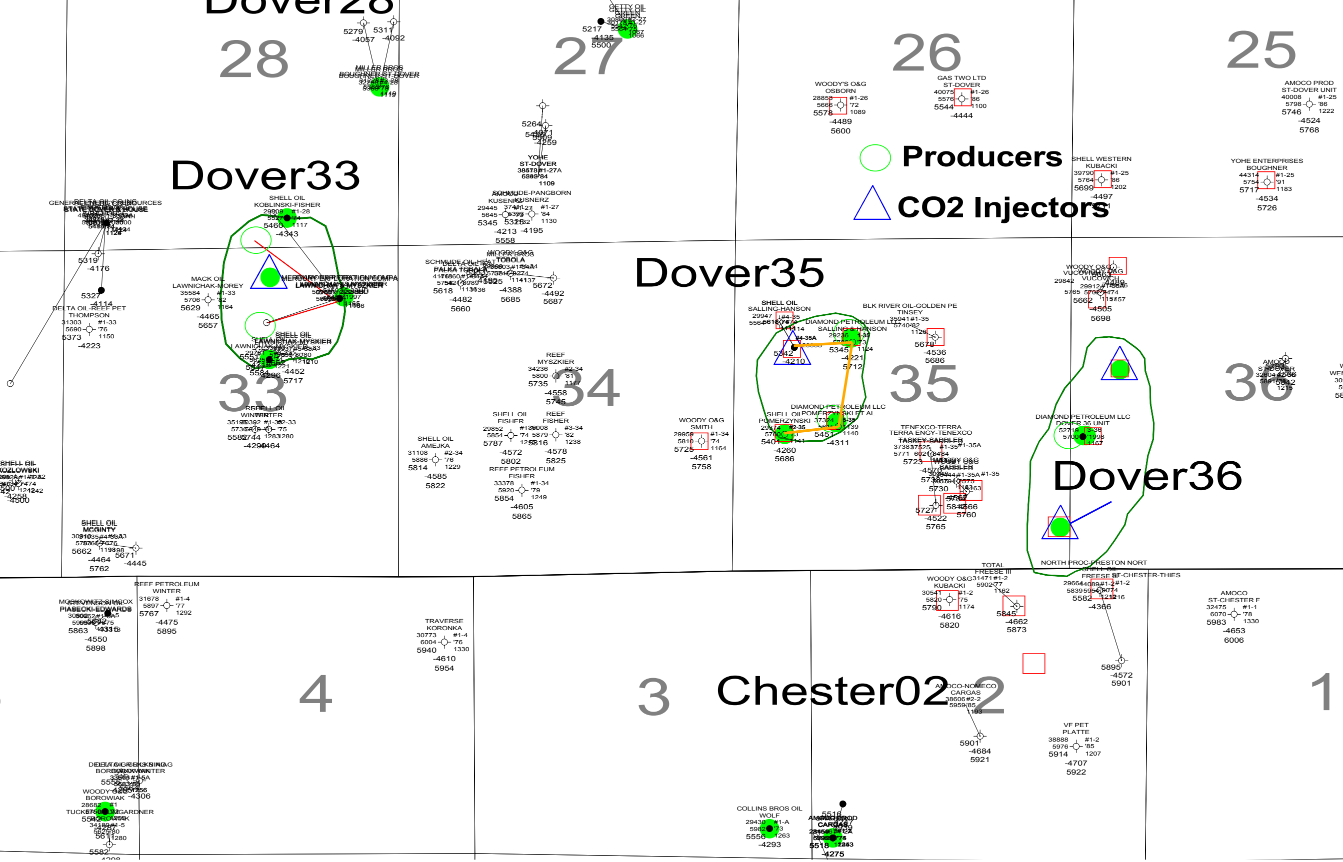



Figure 3. Location map for Dover 35 Field area. The 4 wells in the field are shown inside the green outline. The Salling-Hansen # 4-35 and Salling-Hanson #1-35 wells are the current CO2 injector wells and the Pomerzynski #5-35 is the current producer in the demonstration project. Data posted around the well spots is operator, well name, well number, year drilled, KB, permit number, total depth, top Niagaran Brown measured and subsea depths, and top Niagaran Gray measured depth; small well spots are shallow Antrim wells. Section 35 is one square mile. North is towards the top of the map. Orange lines indicate the cross section shown in Figure 19.

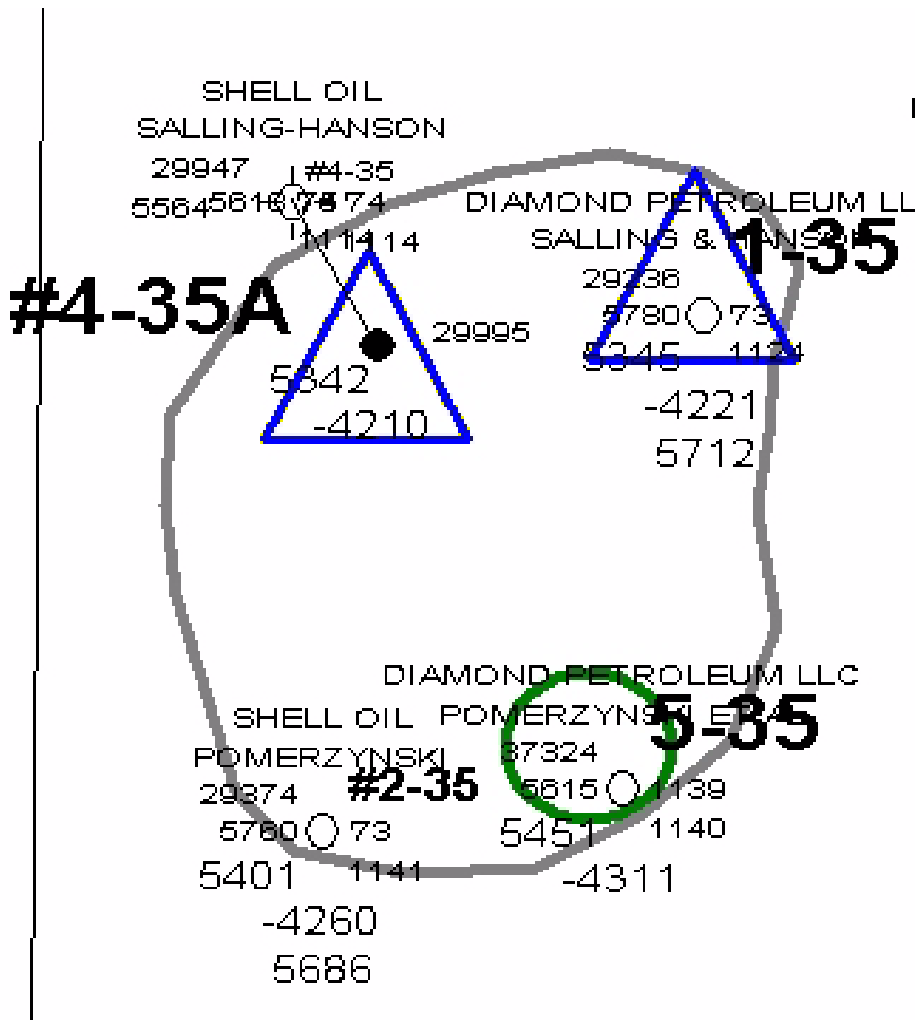



Figure 4. Detail map of Dover 35 CO2 injection field in Otsego County, Michigan. Green well spot indicates the producing well and blue triangles indicate the two CO2 injector wells. Location of Dover 35 is Section 35, T31N, R02W and North is toward the top of the page. Well 5-35 is 1480 feet south of well 1-35.

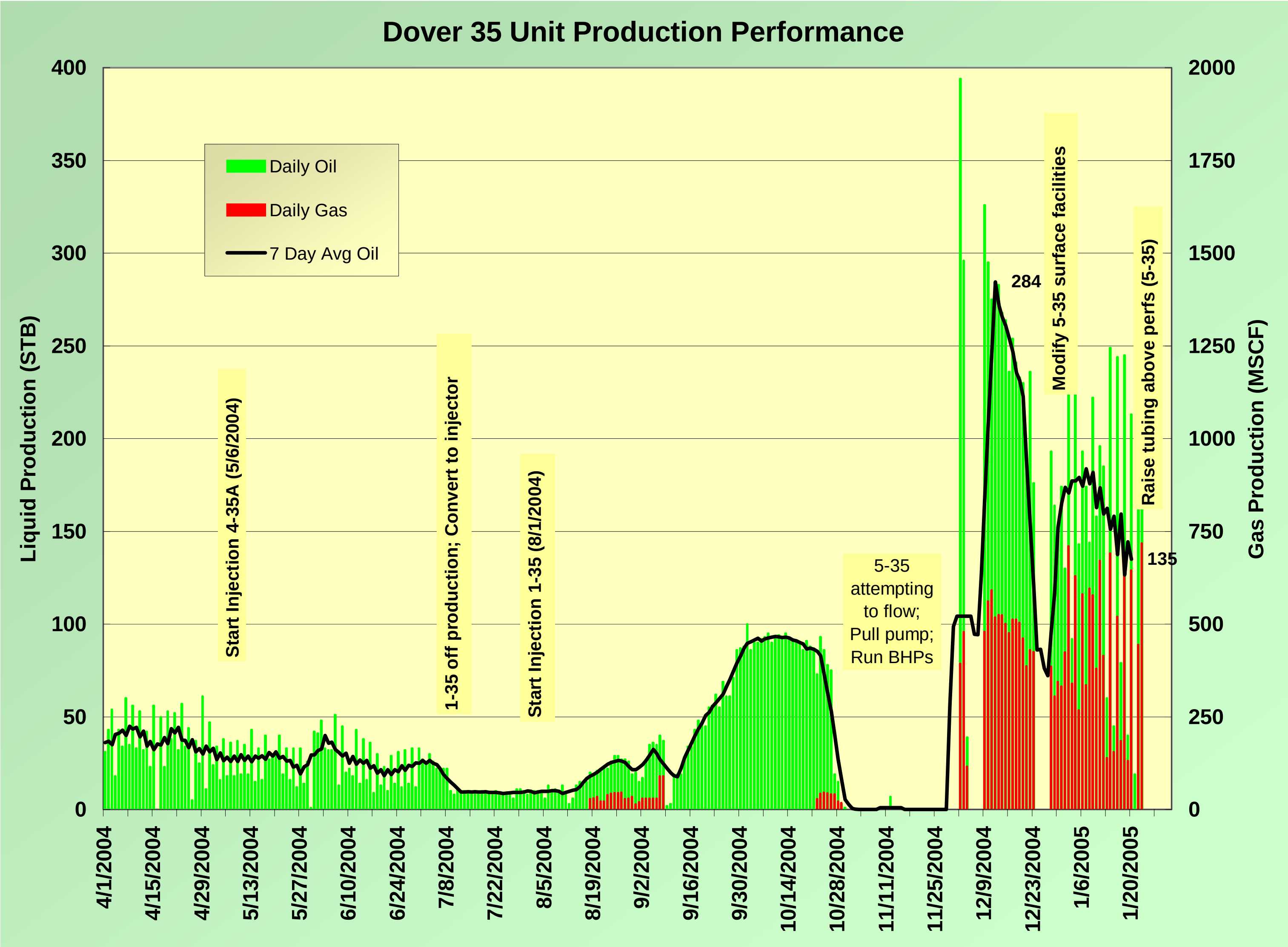



Figure 5. Dover 35 production performance graph showing gas (red), oil (green), seven-day average oil (dark green), and mechanical events for the startup of the CO2 injection. STB is stock tank barrels of oil and MSCF is thousands of standard cubic feet of gas. Note the production response in the 5-35 well approximately 2 weeks after start of injection into the 1-35 well. Seven day average oil rates are shown for December 12, 2004 (284 bopd) and January 20, 2005 (135 bopd).

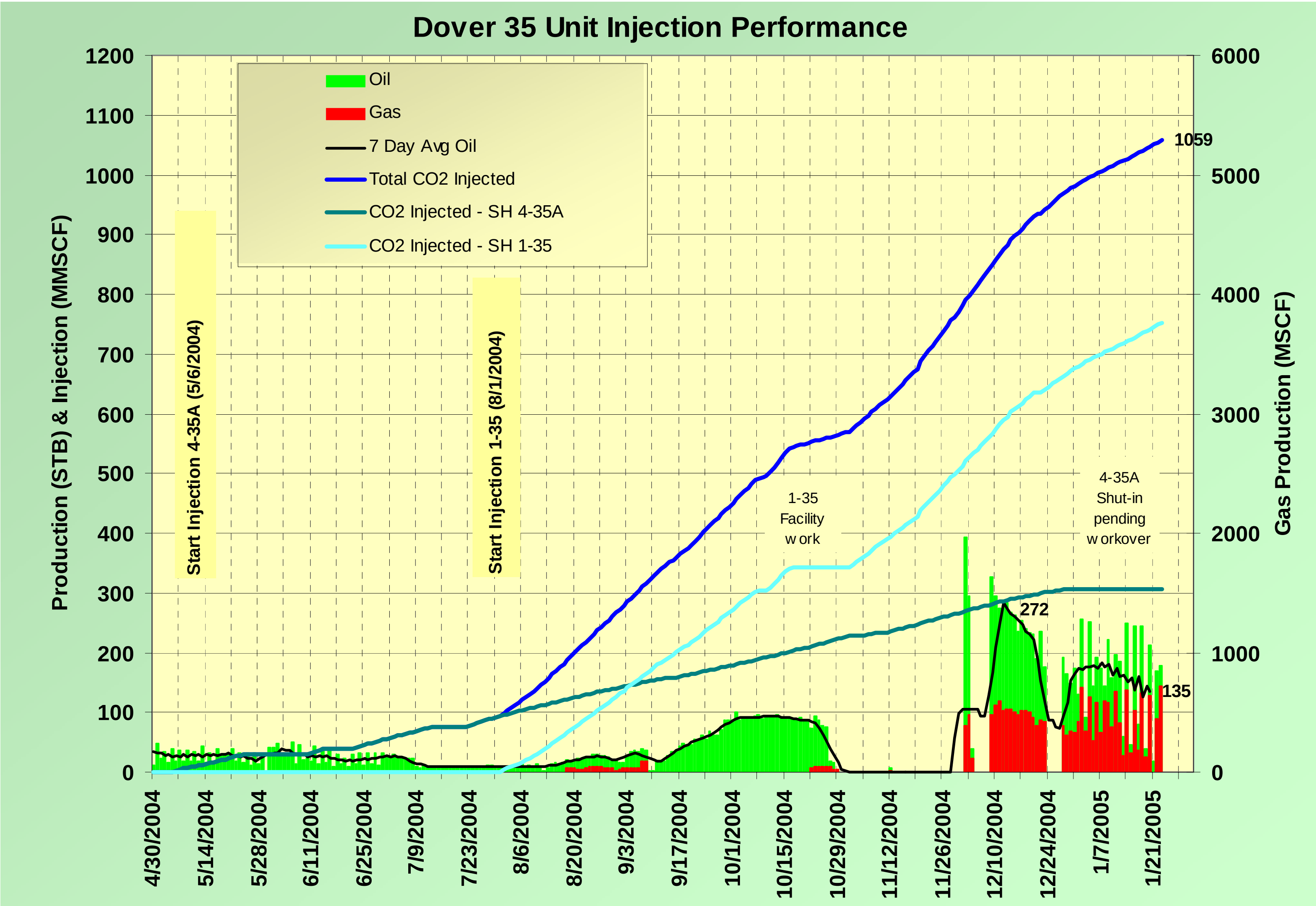



Figure 6. Dover 35 production and CO2 injection performance showing gas (red), oil (green), seven-day average oil (dark green), individual cumulative injection by well (4-35A and 1-35), and cumulative CO2 injection. CO2 injection began on May 6, 2004 into the 4-35A, and on August 1, 2004 into the 1-35. Seven day average oil rates are shown for December 13, 2004 (272 bopd) and January 20, 2005 (135 bopd). Original graph courtesty of Core Energy, LLC.

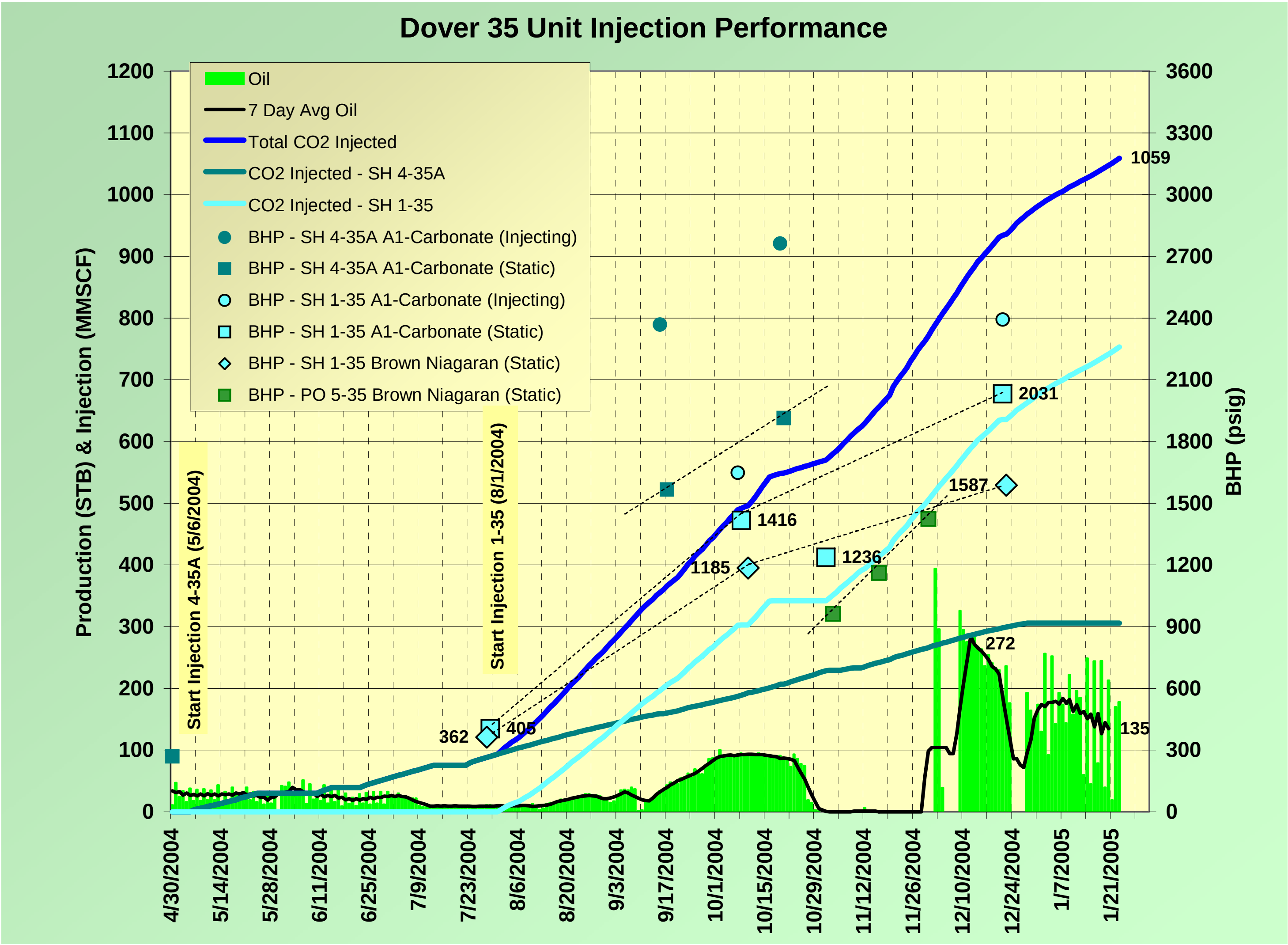



Figure 7. Dover 35 production and CO2 injection performance and bottom hole pressure (BHP) build-up test results. The static BHP tests in the 1-35 well indicate a divergence in pressure increase between the A1-Carbonate (injection interval in the 4-35A and 1-35) and the Brown Niagaran. The BHP divergence between these two zones clearly indicates that CO2 mobility is being affected by heterogeneity in the carbonate reservoir. Seven day average oil rates are shown for December 13, 2004 (272 bopd) and January 20, 2005 (135 bopd). Static bottom hole pressure values for the 1-35 are also posted on the chart. Static BHP trend lines added for clarity. Original graph courtesty of Core Energy, LLC.

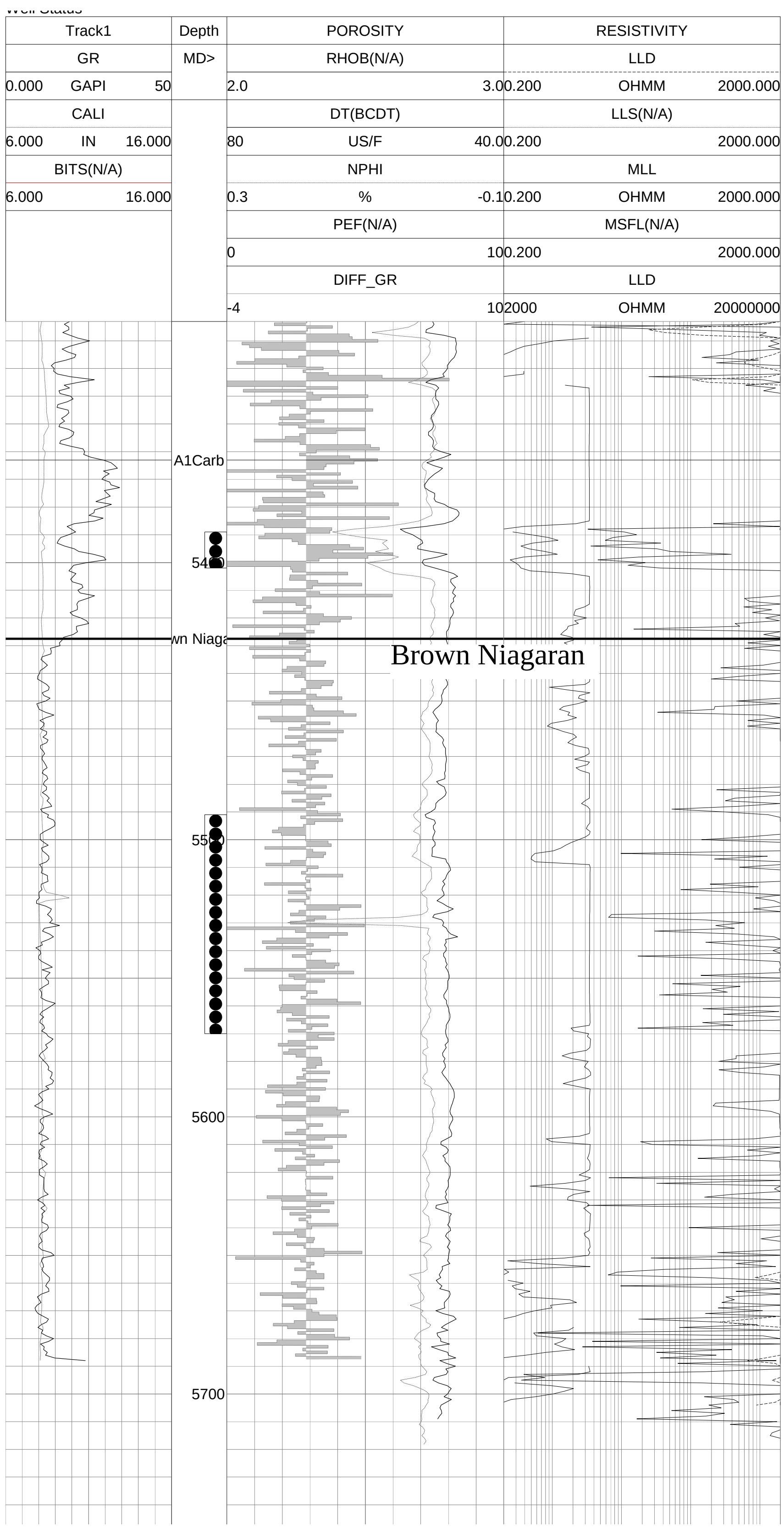



Figure 8. Salling-Hanson 4-35A well log curves and perforated intervals.

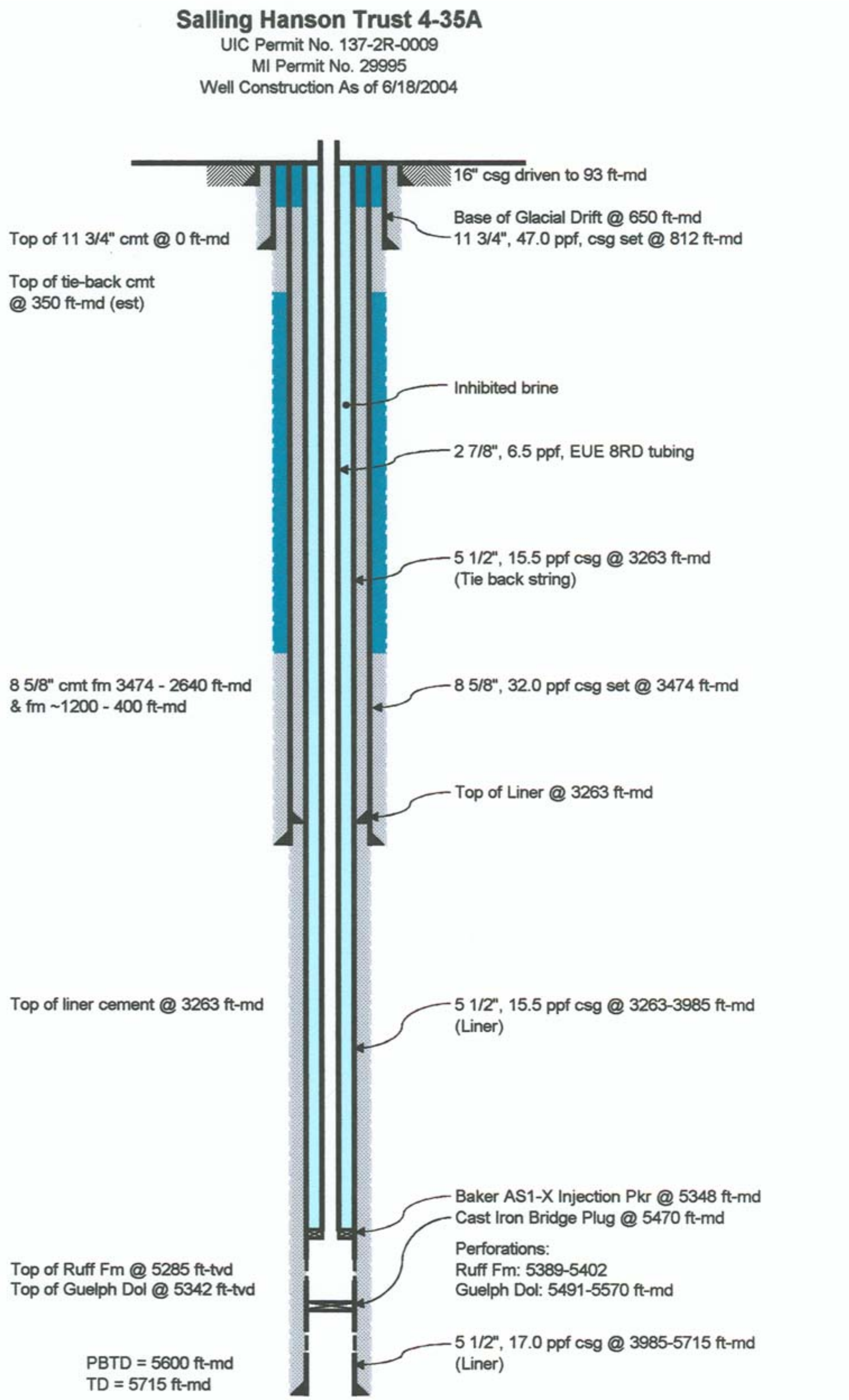



Figure 9. Salling-Hanson 4-35A well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

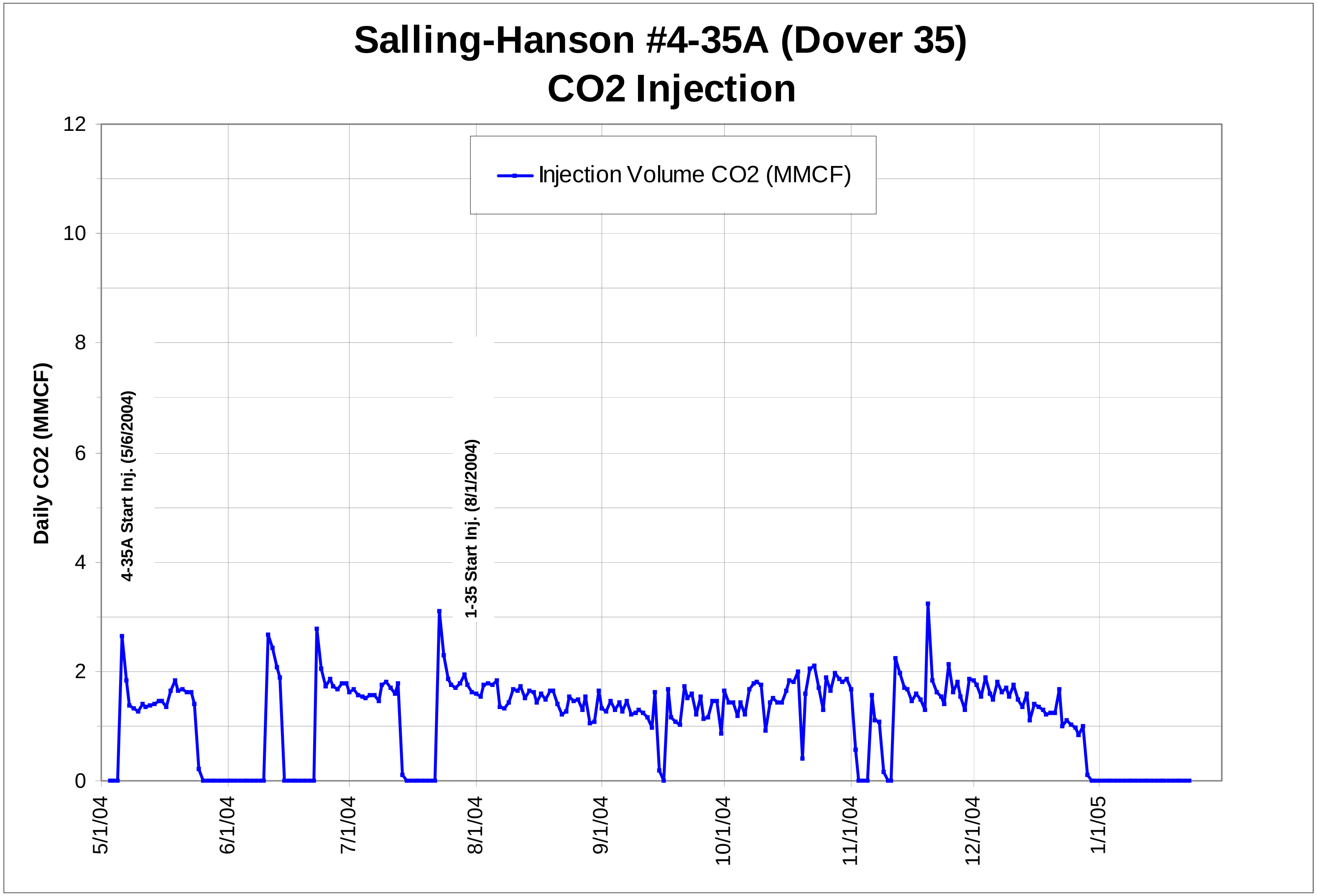



Figure 10. Salling-Hanson 4-35A daily CO2 injection chart. The well was shut-in on December 29, 2004 in preparation for a work-over of the well bore.

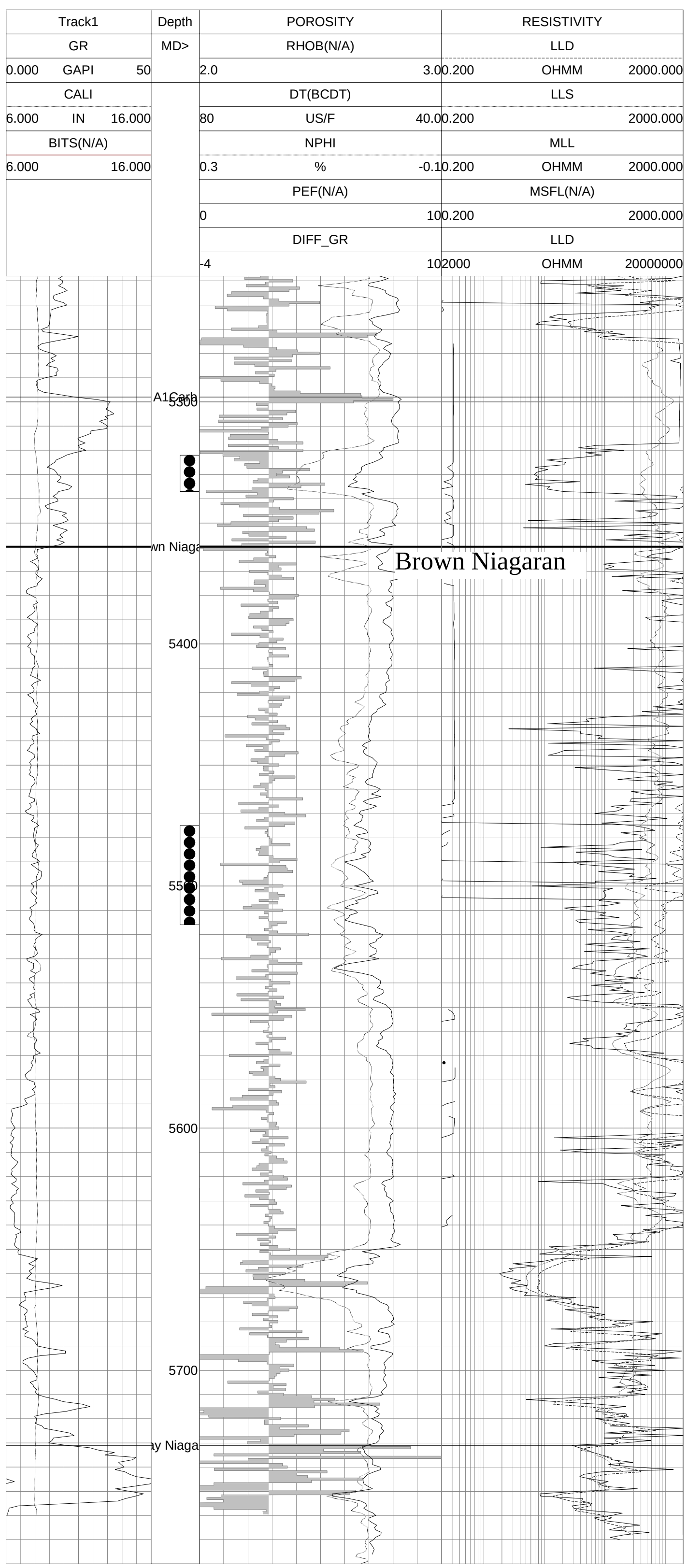



Figure 11. Salling-Hanson 1-35 well log curves and perforated intervals.

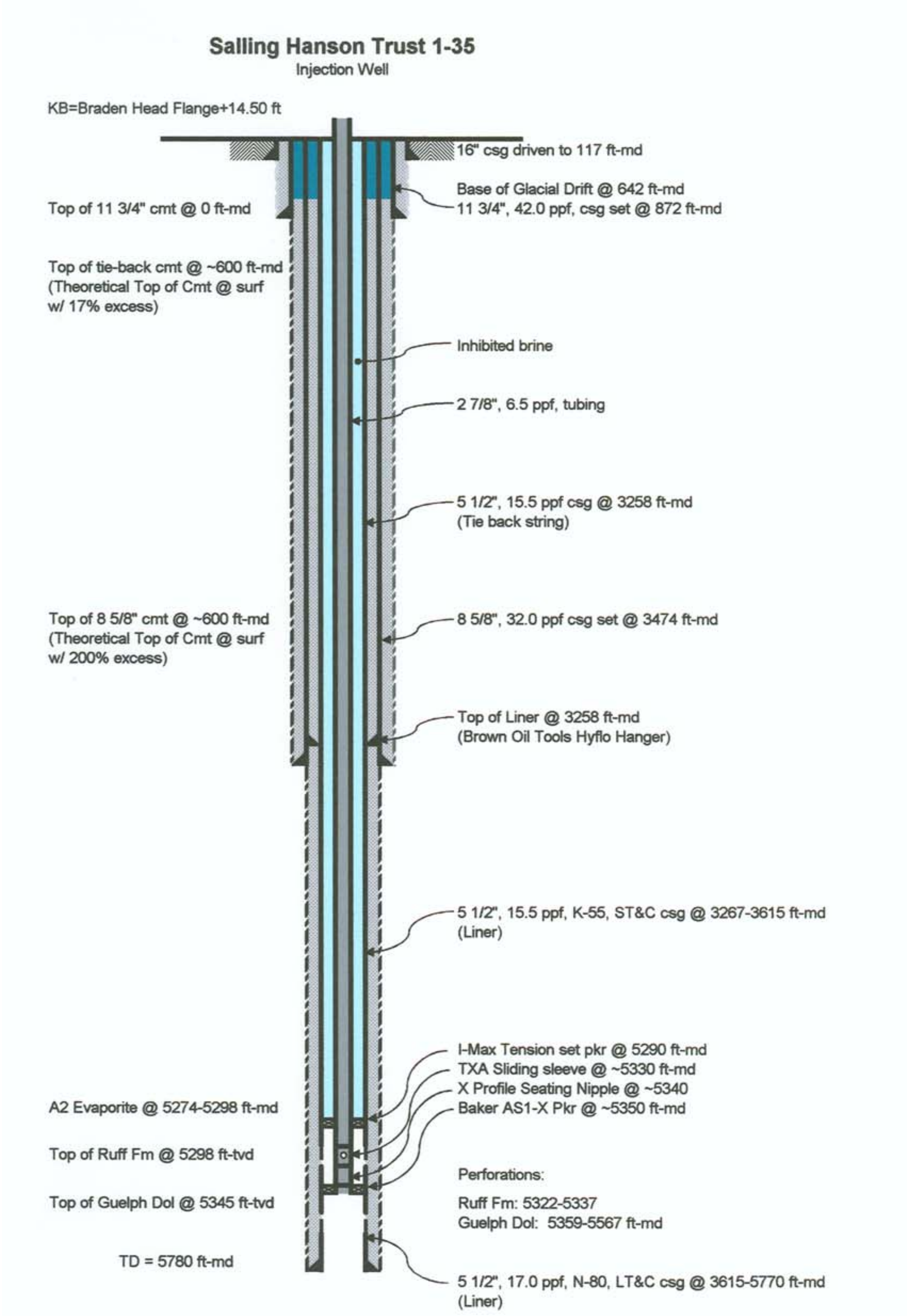



Figure 12. Salling-Hanson 1-35 well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

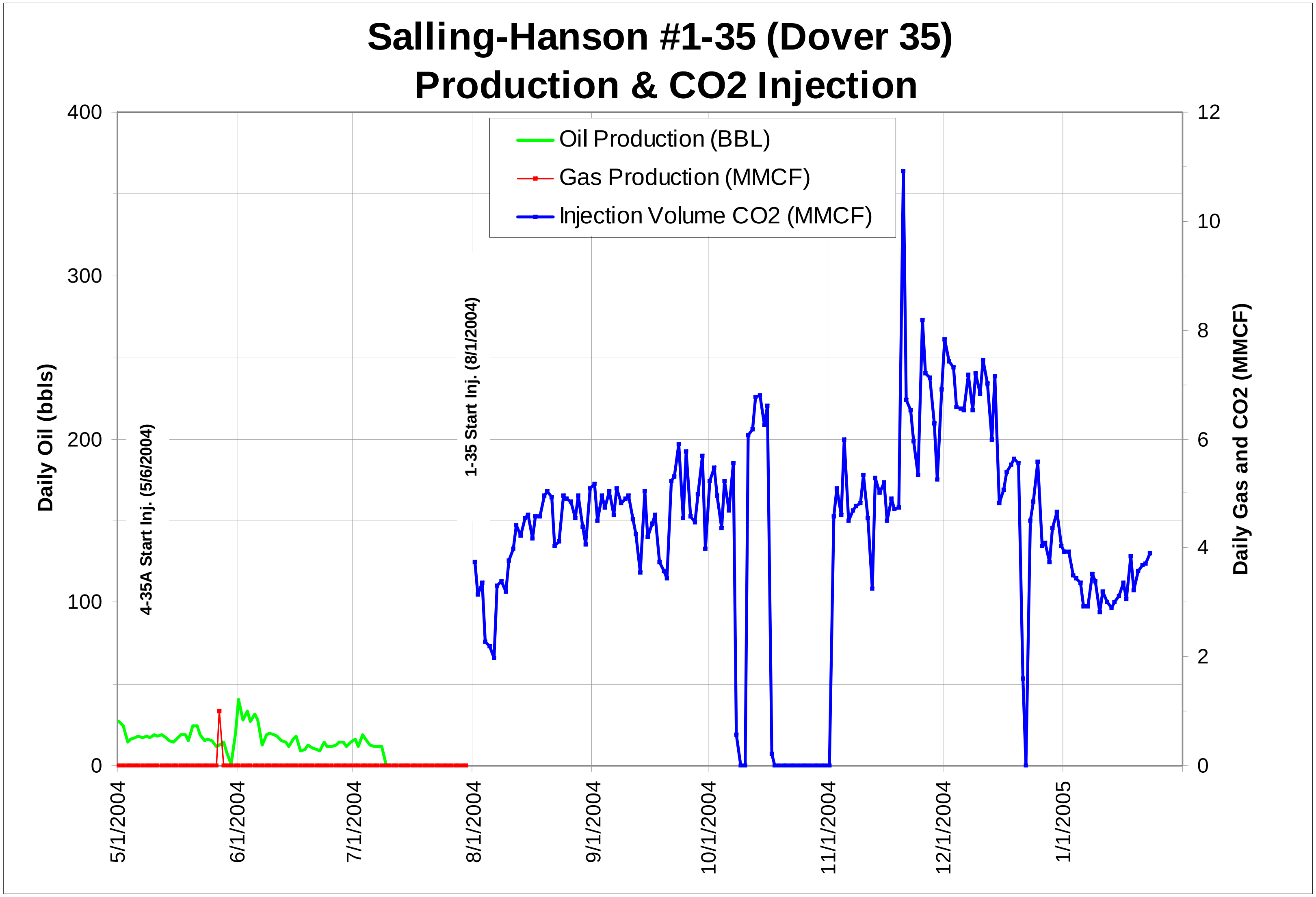



Figure 13. Salling-Hanson 1-35 daily production and CO2 injection chart. The 1-35 was converted in July, 2004 from a producing well to the second CO2 injection well in the Dover 35 field.

| | |
|---|---|
| Well | Pomerzynski 5-35 |
| Well ID | 21137373240000 |
| Field | Dover 35 |
| County | Otsego |
| State/Prov | |
| Country | U.S.A |
| Legal Description | |
| Well Status | |

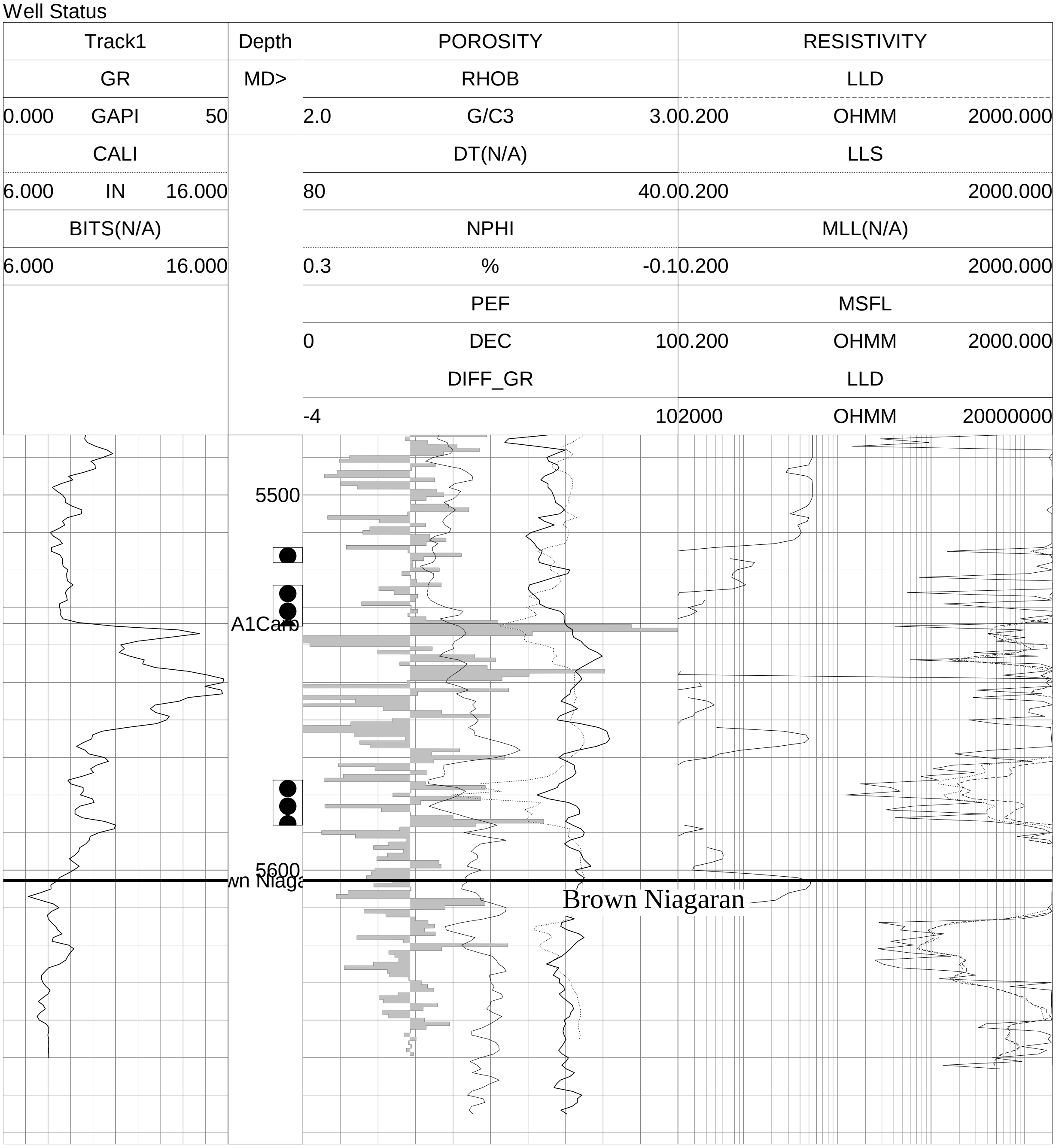



Figure 14. Pomerzynski 5-35 well log curves and perforated intervals.

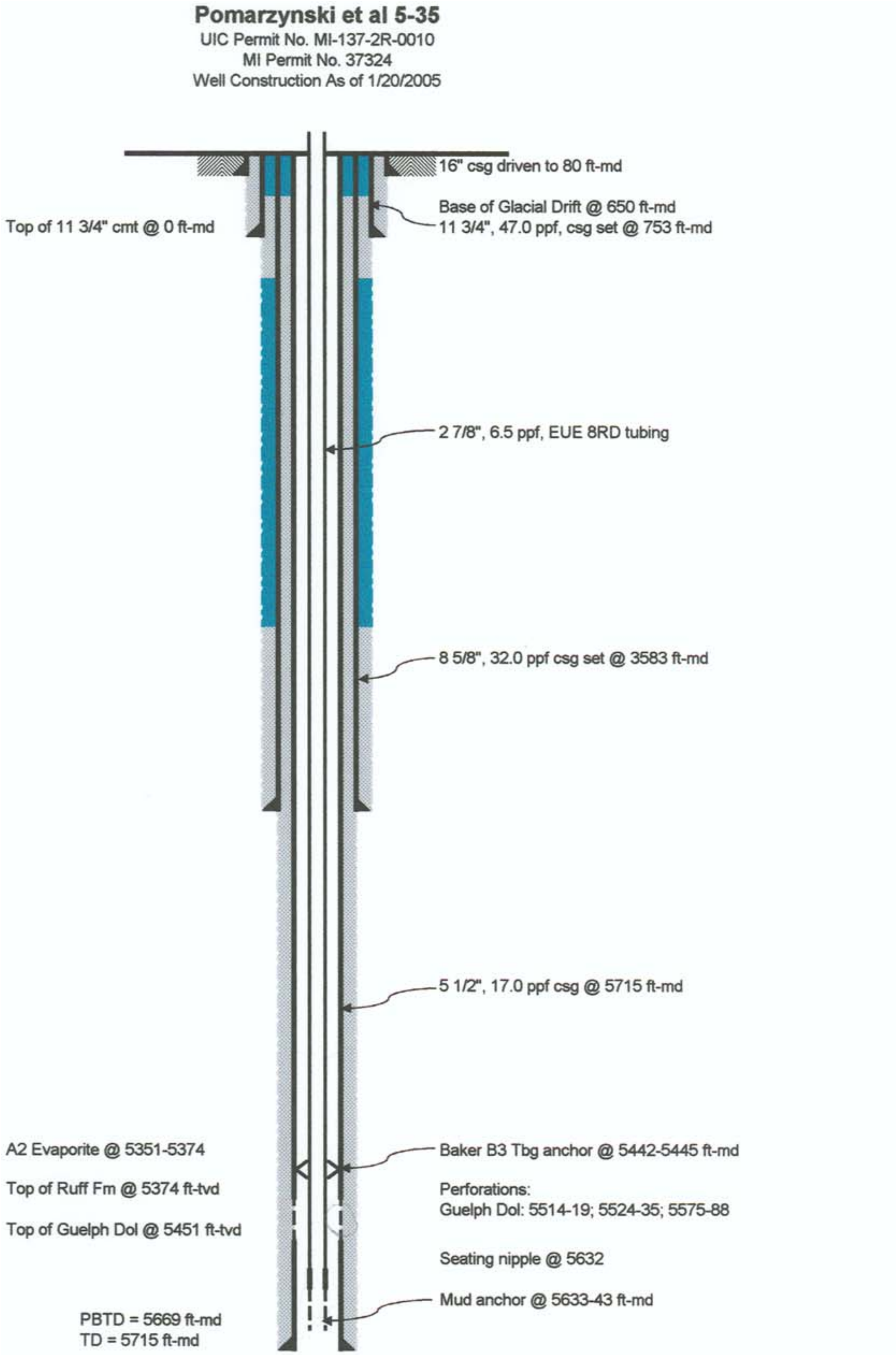



Figure 15. Pomerzynski 5-35 well bore diagram showing downhole mechanical configurations. Diagram provided by Core Energy, LLC.

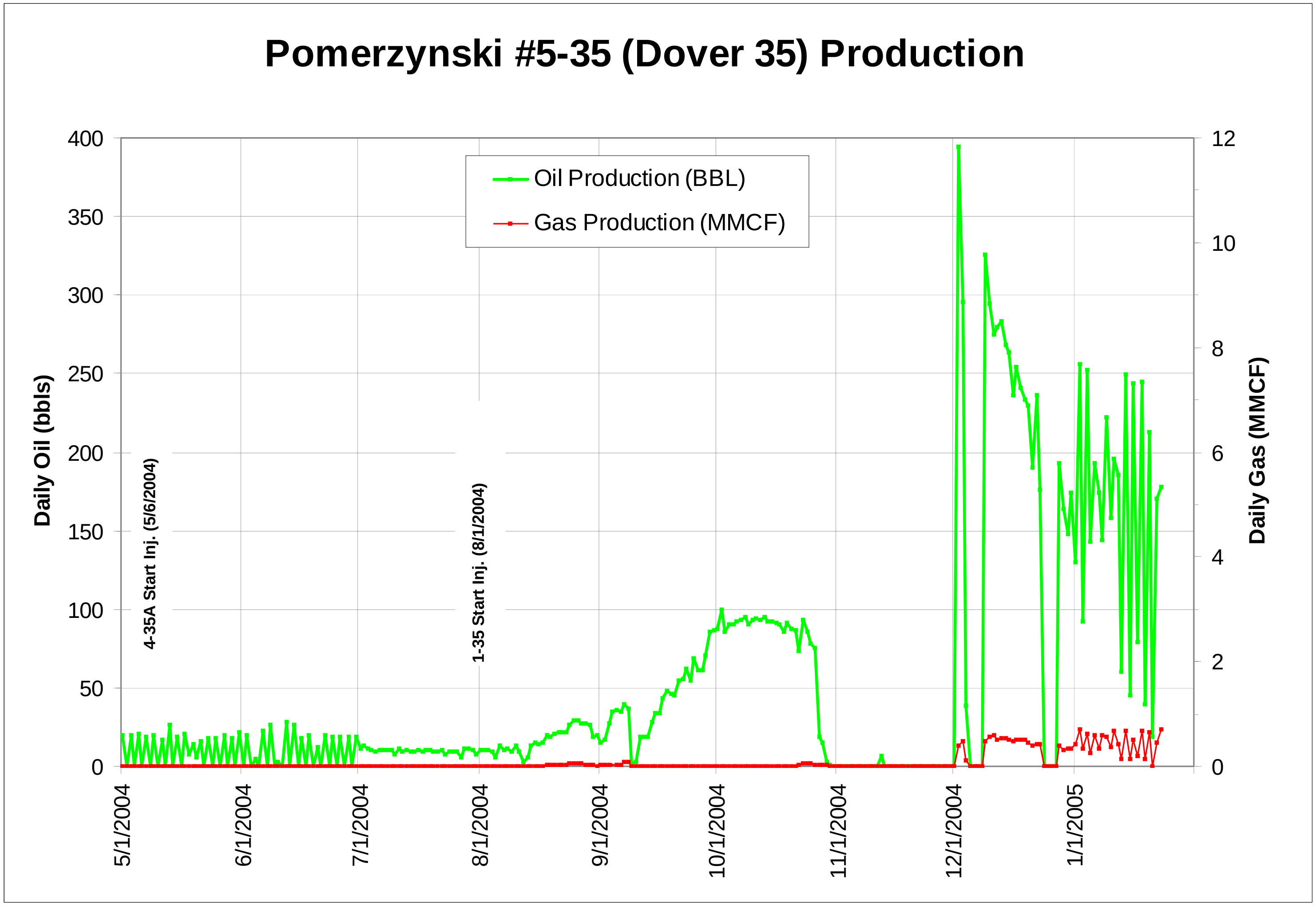



Figure 16. Pomerzynski 5-35 daily production chart. Production response was seen in this well within two weeks of CO2 injection start-up in the 1-35. During October, 2004 the well began to produce significant gas and was attempting to flow. During November, 2004, the well was converted from pumping to flowing, and after swabbing, produced over 200 bopd. However the well continues to experience fluid loading problems because the base of the tubing is below the perforations. The well is currently being worked over to raise the tubing above the perforations to improve production performance.

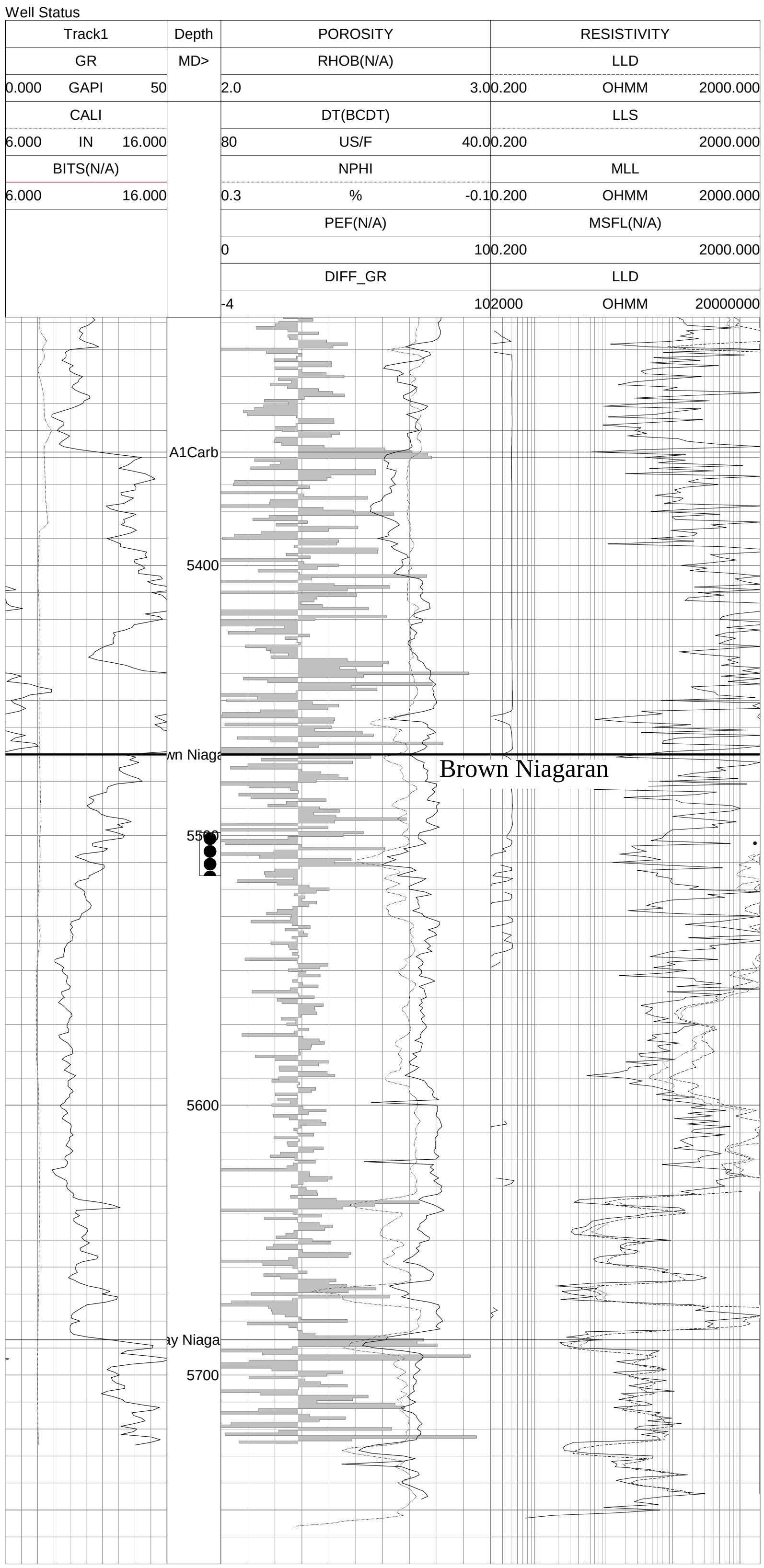



Figure 17. Abandoned Pomerzynski 2-35 well log curves and former perforated interval.

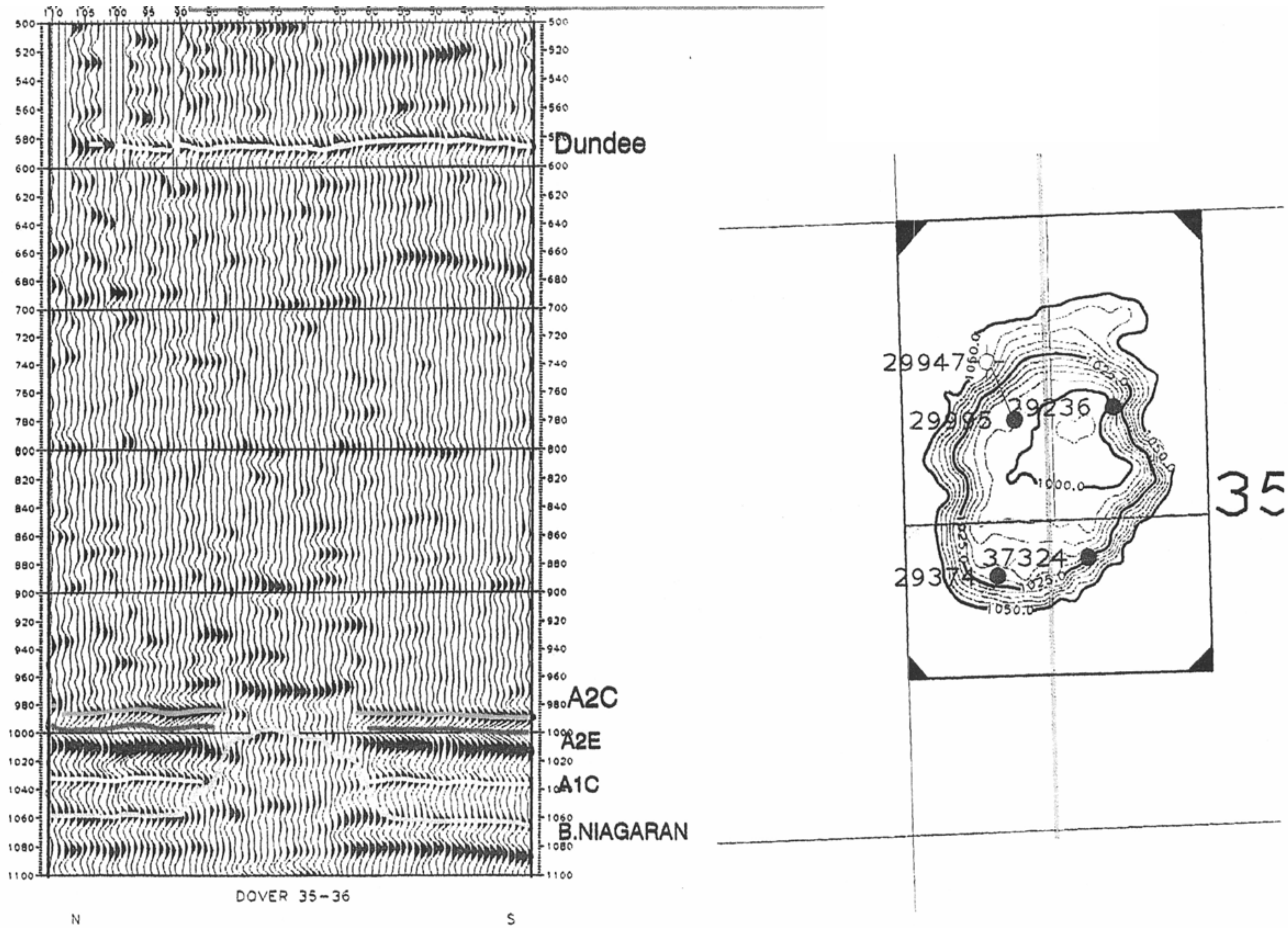



Figure 18. Example west-east panel through Dover 35 3D seismic volume provided by industry partner.  Note absence of seismic reflections over the Dover 35 field that is a characteristic seismic signature of Niagaran reefs.

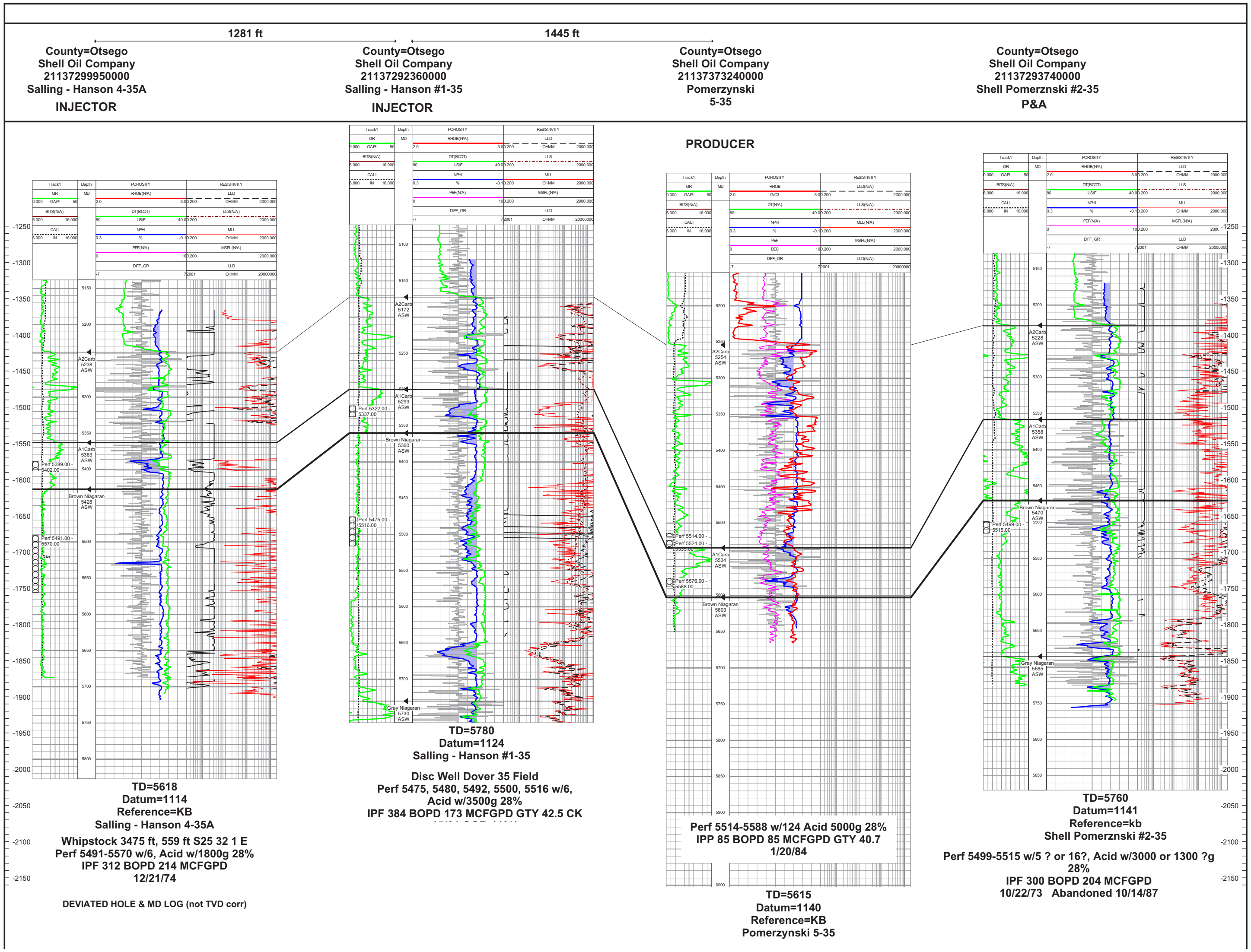



Figure 19. Structural cross section through the four wells in the Dover 35 Field in Otsego County, Michigan with the A2 Carbonate, A1 Carbonate, Brown Niagaran, and Gray Niagaran correlations. Line of cross section is shown in Figure 3. CO2 is currently being injected into the Salling-Hansen #4-35A and the Salling Hansen #1-35. Oil and gas production is from the Pomerzynski 5-35. Original completion information for the wells is also shown. Refer to Figures 9, 12, and 15 for current mechanical configuration.

| Reservoir Characteristics | Dover 35 | Dover 33 | Dover 36 |
|---|---|---|---|
| | | | |
| Reservoir Geologic Type | Pinnacle Reef | Pinnacle Reef | Pinnacle Reef |
| Reservoir Geologic Age | Silurian | Silurian | Silurian |
| Lithology | Dolomite/Limestone | Dolomite | Dolomite/Limestone |
| Depth (top reservoir) | 5,320' | 5,300' | 5,320' |
| Field Area | ~85 Acres | 93 Acres | 195 Acres |
| Porosity Type | Vugular and intercrystalline | Vugular and intercrystalline | Vugular and intercrystalline |
| Average Porosity | 8.0% (est.) | 7.1% | 6.9% |
| Permeability | Unknown - No Cores | Unknown - No Cores | Unknown - No Cores |
| Reef Thickness | 410' (includes A-1carb zone) | 360' | 370' |
| Oil Column Thickness | ~220' (includes A-1) | 214' | 300' |
| Average Water Saturation | 25% | 22% | 25% |
| Crude Oil Gravity | 41.5º | 43.6º | 42.8º |
| Initial Reservoir Pressure (psia) | 2946 | 2894 | 2996 |
| Reservoir Temperature | 104º F | 108º F | 108º F |
| Bubble Point Pressure (psia) | 2050 | 2100 | 1870 |
| Initial Solution GOR (scfg/stbo) | 450 | 650 | 608 |
| OOIP by Material Balance | 2.2 MMstbo | 4.1 MMstbo | 3.64 MMstbo |
| MMP (psia) | 1195 | 1195 (2.7bcf, 9 months) | 1195 (2.1bcf, 29 months) |
| Primary Production | 0.966 MMBO & 0.835MMCFG | 1.28MMBO & 1.87MMCFG | 1.149 MMBO & 1.17MMCFG |
| Oil Recover Factor (primary) | ~33% | 31.2% | 31.6% |
| Drive Mechanism | Pressure Depletion, Gravity Segregation | Pressure Depletion, Gravity Segregation | Pressure Depletion, Gravity Segregation |

Figure 20. Table comparing reservoir characteristics between Dover 35, Dover 33 and Dover 36 fields.

### Historical and Predicted Performance - Dover 35, 33 & 36 CO2 EOR Projects

| | PUMPIII Dover 35 | Dover 33 | Dover 36 |
|---|---|---|---|
| Start Date of $CO_2$ injection | May-2004 | May-1996 | Jan-1997 |
| Cumulative oil production @ start of $CO_2$ injection | 966 MBO | 1,280 MBO | 1,149 MBO |
| Estimated ultimate primary oil production | 992 MBO | 1,360 MBO | 1,160 MBO |
| Estimated original oil in place (material balance) | 2,243 MBO | 4,100 MBO | 3,730 MBO |
| Volume of oil produced since CO2 injection | 15 MBO** | 450 MBO | 220 MBO |
| Estimated remaining oil reserves | 235 to 585 MBO | 300 MBO | Unknown |
| Estimated ultimate oil recovery (primary + $CO_2$) | 1,234 MBO | 2,027 MBO | Unknown |
| Estimated ultimate oil recovery by $CO_2$ process | 250 to 600 MBO | 750 MBO | Unknown |
| $CO_2$ injected to reach minimum miscibility pressure (1200 psi) | in progress | 2.7 BCF | 2.1 BCF |
| Total $CO_2$ injected (initial & recycled) | 1.047 BCF* | 20.5 BCF | 5.4 BCF |
| Other substances injected: | | | |
| Water | | 11,000 Bbls | 0 |
| Other Substances | | 0 | 0 |

**as of January 20, 2005

*as of December 31, 2004

Figure 21. Historical and predicted performance for Dover 35, Dover 33 and Dover 36 fields, including cumulative production, reserves, and estimated ultimate recovery.

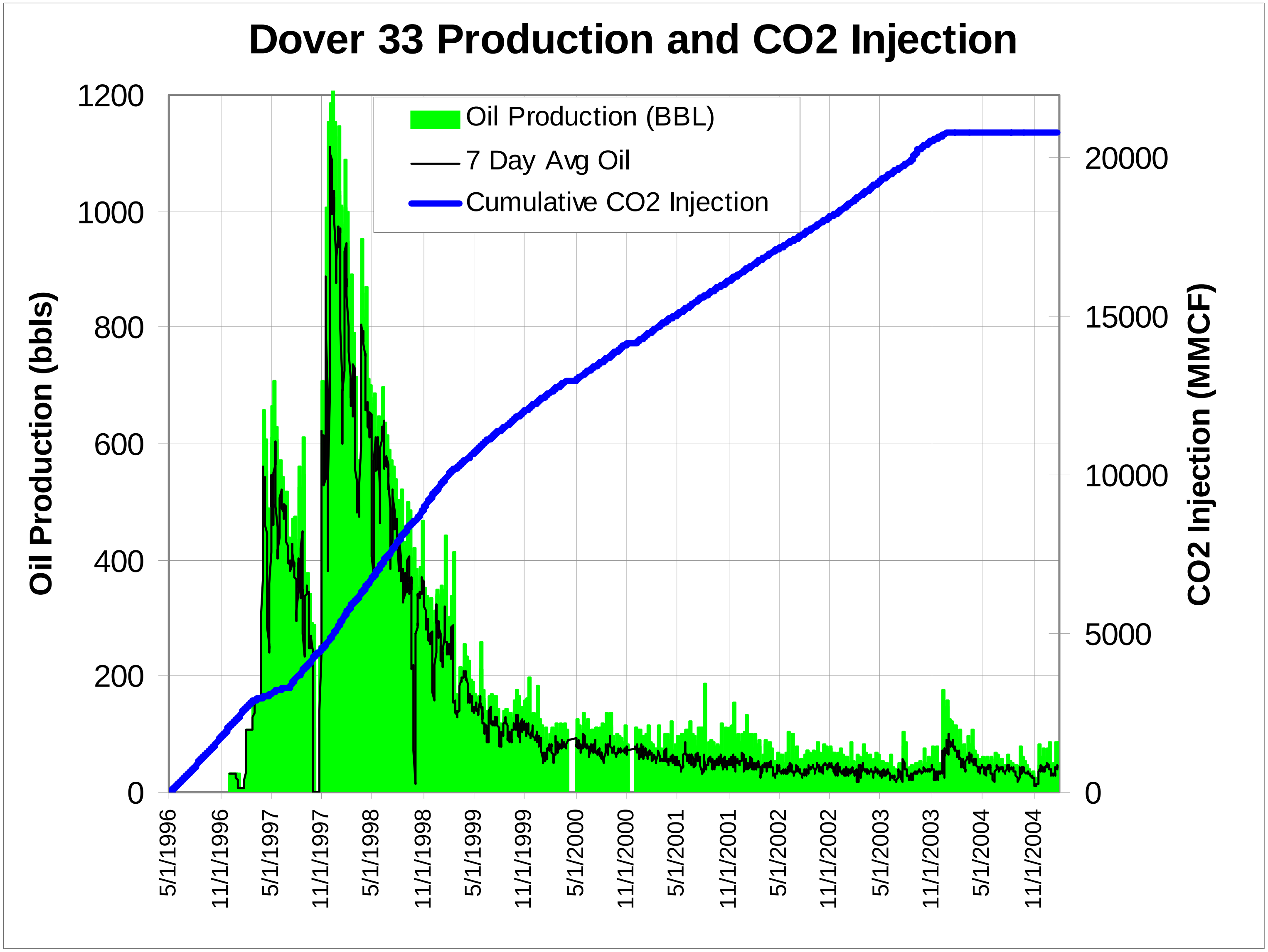



Figure 22. Dover 33 daily oil production and cumulative CO2 injection.

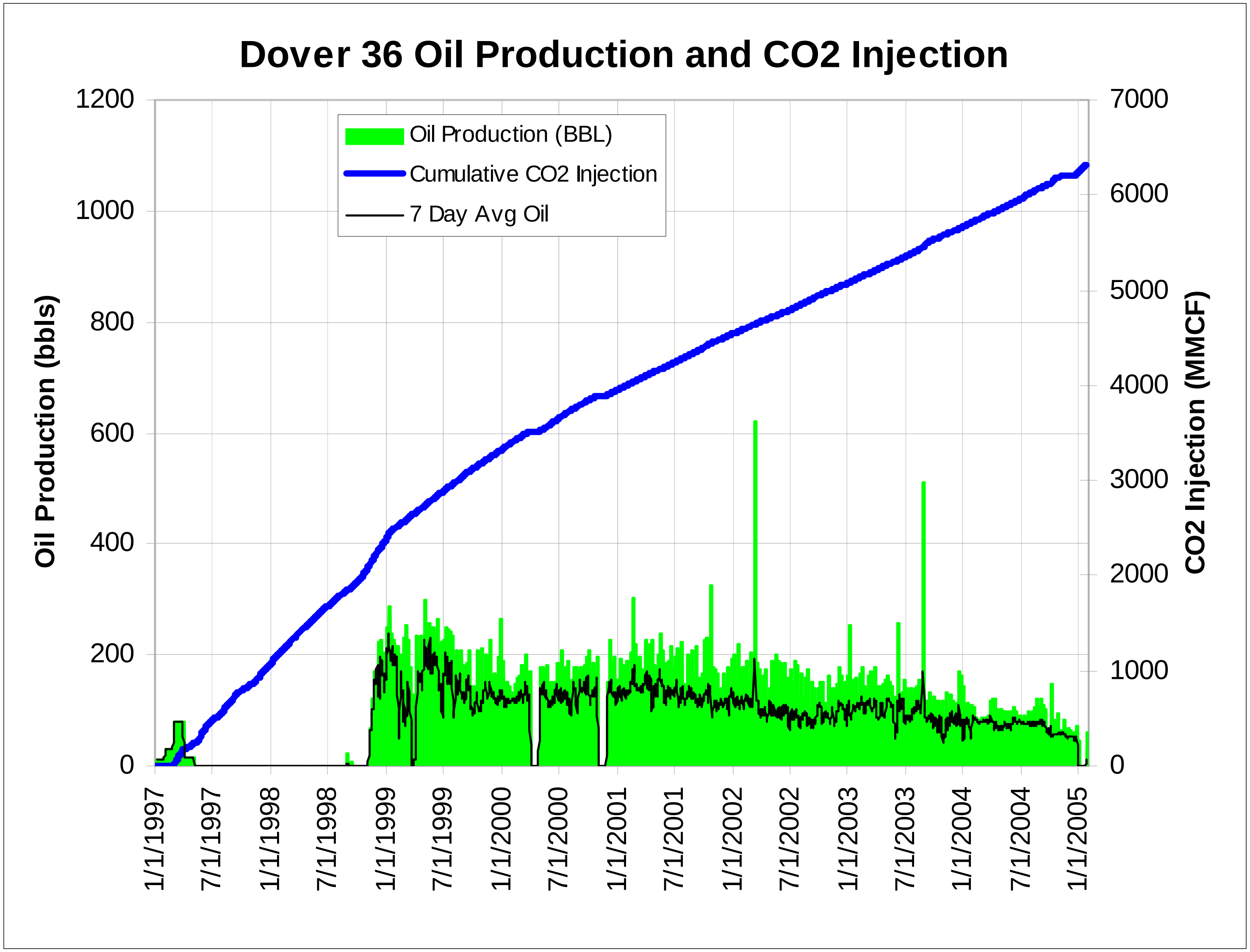
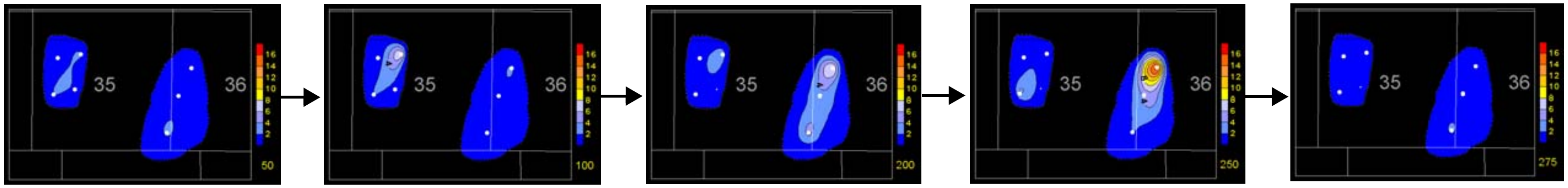
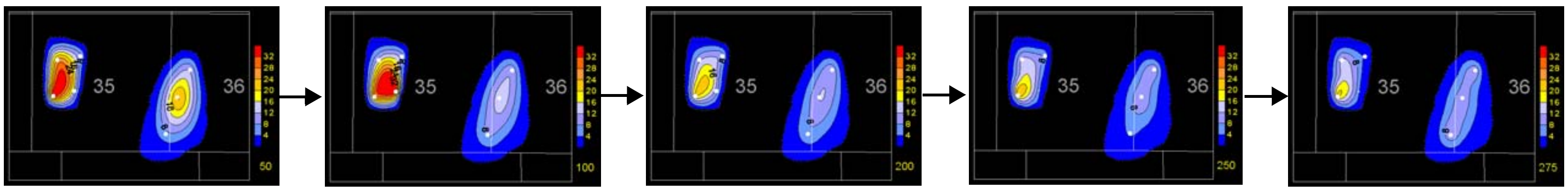



Figure 23. Dover 36 daily oil production and cumulative CO2 injection.

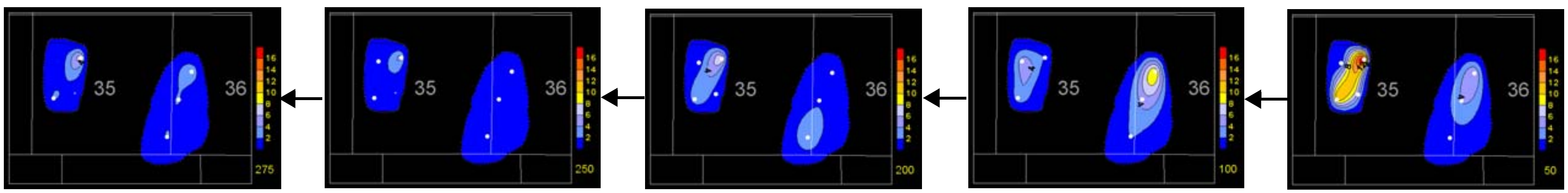
**LOG POROSITY: TOP-DOWN SLICING FROM REEF TOP TO REEF BASE**




**GAMMA RAY: TOP-DOWN SLICING FROM REEF TOP TO REEF BASE**




**LOG POROSITY: BOTTOM-UP SLICING FROM REEF BASE TO REEF TOP**




**GAMMA RAY: BOTTOM-UP SLICING FROM REEF BASE TO REEF TOP**

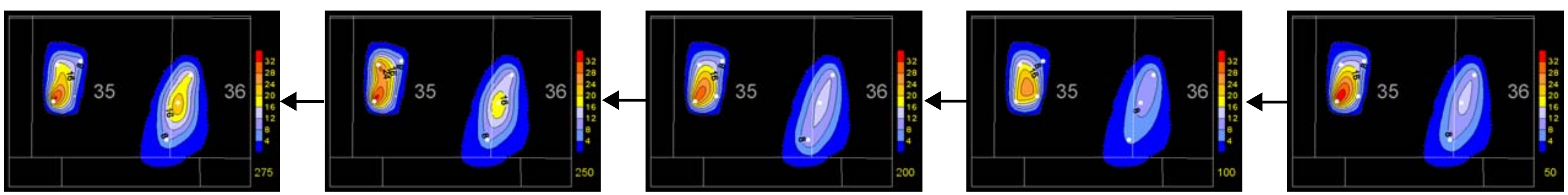



Figure 24. Dover 35 and Dover 36 Well Log Tomography slices. Color Scale is in percent porosity with a Contour Interval of 2 phi for Log Porosity slices, and Color Scale is in API units with a Contour Interval of 4 api for Gamma Ray slices. Slice number is feet above reef base or below reef top. North is toward the top of each map.

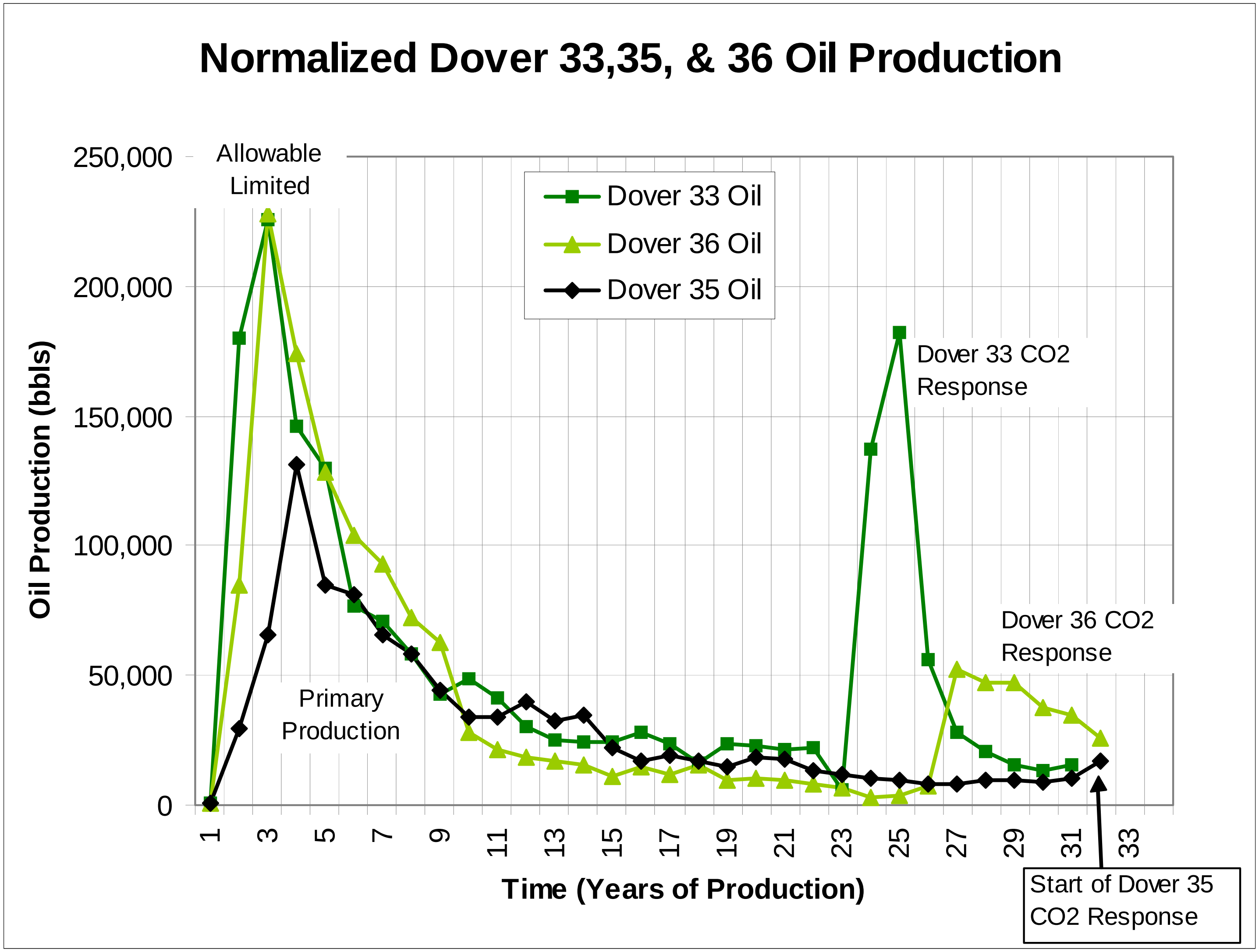



Figure 25. Plot of normalized historical annual oil production for the Dover 33, Dover 36, and Dover 35 fields. Note the similarity in the performance of the three reservoirs during primary production. However, CO2 injection resulted in significant differences in tertiary recovery-approximately 450 MBO for Dover 33 versus 220 MBO for Dover 36. Dover 35 is still in the beginning stages of tertiary recovery.

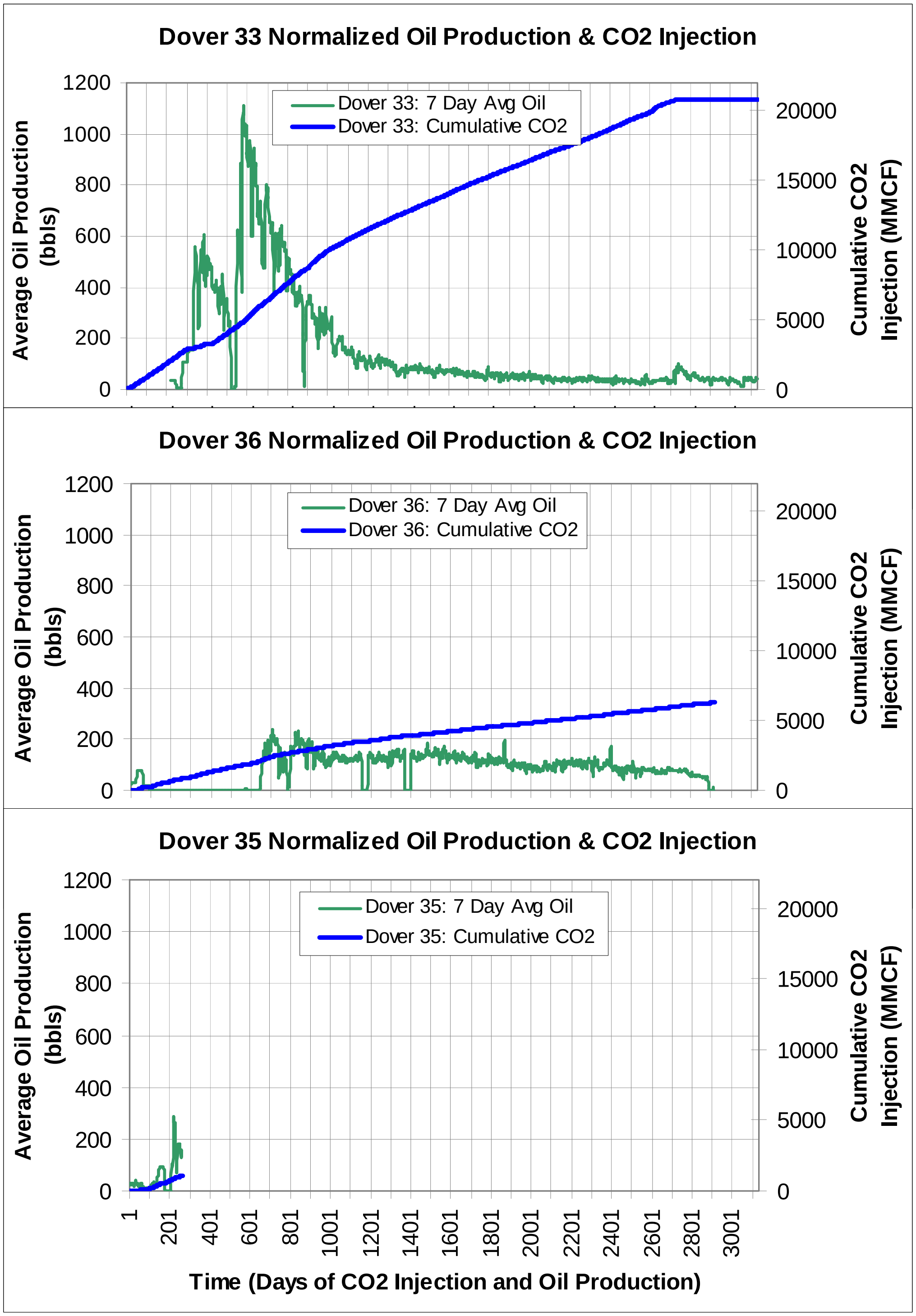



Figure 26. Plot of normalized daily cumulative CO2 injection and seven-day average oil production for the Dover 33, Dover 36, and Dover 35 fields where the time scale begins on the first day of CO2 injection for each field. Cumulative CO2 injection into Dover 33 is 20.5 BCF versus 5.4 BCF for Dover 36. Injection pressures (not shown) were also higher for Dover 36 versus Dover 33 (approximately 1100 psig versus 600 psig). These performance differences are being examined and will be discussed in a future report. Dover 35 is anticipated to parallel the performance of Dover 33.

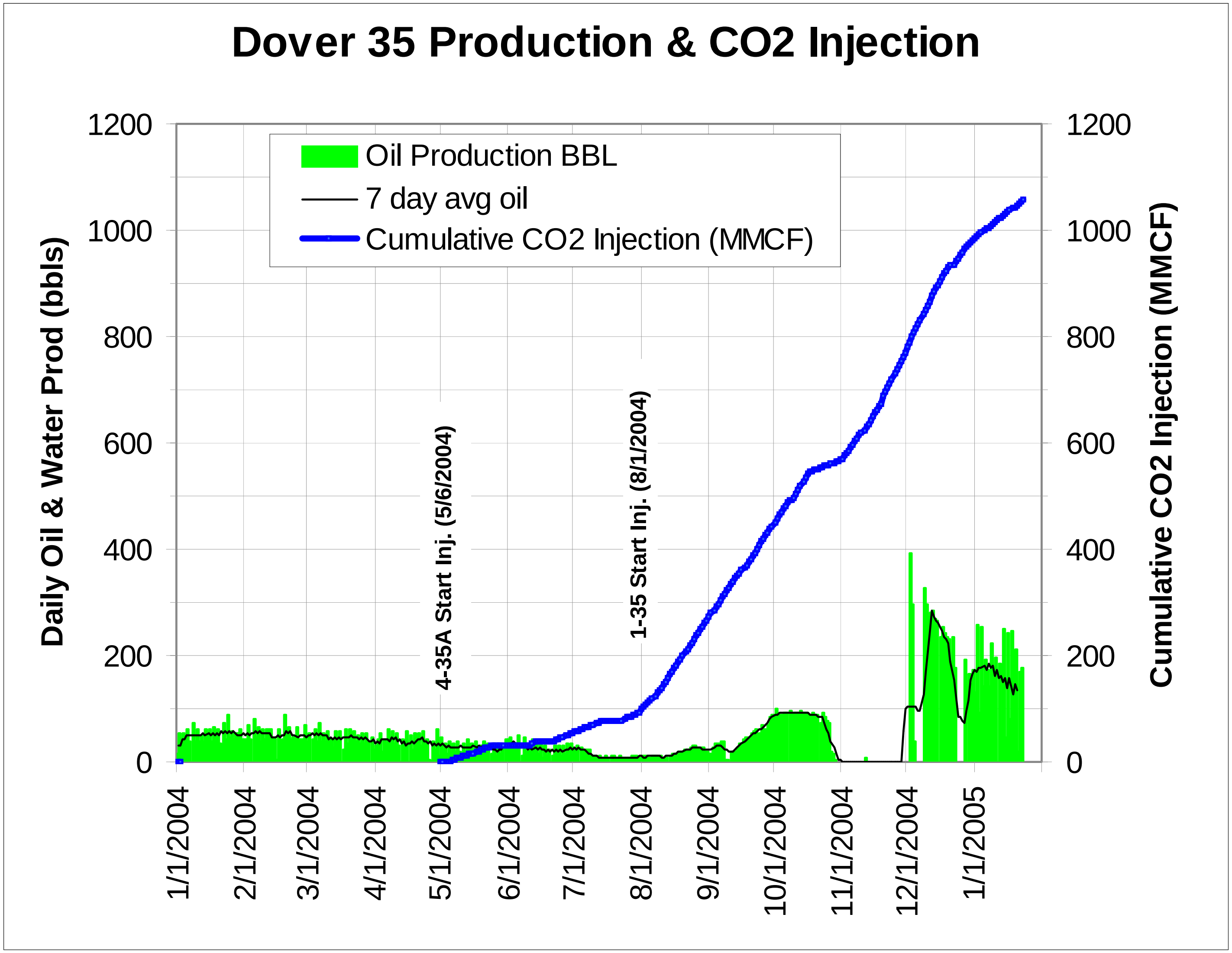



Figure 27. Dover 35 daily oil production and cumulative CO2 injection. The 1-35 produced approximately 30 BOPD before conversion to injection.